CHAPTER 9

INSTRUMENTS AND CONTROLS

9-1. General.

This chapter addresses the criteria for the selection of instruments and controls to meet the requirements of the steam plant.

a. Pneumatic controls. Most control system manufacturers have discontinued production of pneumatic controls systems. Replacement parts and qualified service for the equipment are difficult to procure. For these reasons pneumatic controls should not be used for new installation.

b. Electronic controls. Electronic systems have been made obsolete by the microprocessor based control systems. Manufacturers no longer make electronic control systems and they should not be specified for new installations.

c. Microprocessor based controls. Microprocessor based control systems can provide sequential logic control and modulating control in one control device. This capability makes available boiler control systems, which use both sequential logic and modulating control, that are more flexible and reliable as well as more cost effective. Processing units can be utilized as single loop controllers or more powerful processing units can be applied to individual control subsystems, such as combustion control of ash handling control.

(1) Inputs from and outputs to field devices may be multiplexed. Data highways connect all processing units to data storage and acquisition components, cathode ray tube (CRT) displays and operator consoles, loggers, and printers, providing communication among all components. Communications between modulating control devices and sequential logic flow freely and are not subject to the restrictions inherent with analog and mechanical relay electronic systems which require hard-wiring between components. Data acquisition and operator interface for control may be accomplished using CRT's, keyboards and printers or through control stations indicators and recorders mounted on an operator console. When CRT's, keyboards and printers are utilized redundant microprocessors are sometimes utilized depending on unit size.

(2) Program logic can be changed or expanded readily with limited hardware revisions. System selection can range from programmable controller systems to fully distributed digital control systems. The criteria for selection of the proper microprocessor based system will include unit size, the amount and type of modulating control and sequential logic required, operator interface requirements, system security requirements, and LCCA.

(3) Distributed control systems include the process input output sensors and actuators which are connected to the termination units which condition and multiplex the signals for communication to the microprocessor unit controllers where the logic resides for control of the process variable. All microprocessor unit controllers communicate with each other and to a data highway which includes nodes for the operator interface station, engineering work station, and programmable logic controllers for balance of plant controls.

(4) The distributed control system logic for the controls and the 110 for the process are located in the vicinity of the process. This process controller will communicate with other process controllers, engineers work station, data acquisition system and the operator interface. The control system will be configured to allow the process controller to continue to function upon loss of communication with the operator interface, data acquisition system and other process controllers.

d. Control system reliability. The methods used to ensure control system reliability will be based on unit size, importance to plant operation, and the cost of control system failure versus the cost of backup hardware.

(1) *Power sources.* Power to the control system must have a backup supply. Microprocessor based systems must have a backup power supply either from a separate ac source or an uninterruptable power supply (UPS). Loss of either the primary power source or the backup power service must be detected and alarmed. Loss of either supply alone must not affect operation of the controls. Distributed control systems will include power supplies which are redundant or backed up so that loss of any power supply will not cause loss of power to the control logic. Loss of power supply should be alarmed.

(2) *Control system safeguards.* Microprocessor based controls are highly reliable but safeguards must be provided to limit the effects of component failure. Microprocessor based control systems require grounding to a ground mat with an impedance of three ohms or less for protection of system components to reduce forced plant outages. Spare circuit cards for critical components are to be available at the boiler plant, as well as spare microprocessing units that can be

substituted for faulty units which are encountered during start-up and operation of the plant. For critical subsystems consideration should be given to redundant microprocessors with automatic switching of inputs and outputs from one microprocessor to another. The data highway should be looped or redundant so that failure of a segment of the data highway will not result in the loss of communications. Control elements should be designed to fail in a safe condition upon loss of the electric or pneumatic power to the actuators or input signal. The loss of power at the component or subsystem levels must cause the associated auto/manual stations to switch to the manual mode of operation. The control logic should have continuous self diagnostic capability and, upon detection of component failure, transfer to manual and indicate the cause of the failure. Microprocessors are to contain nonvolatile memory which will not be erased on power failure.

e. Control system expansion. The control system architecture should allow expansion at all levels of the system. The 110 can be expanded by installing additional cards or racks with signal conditioning for communication to the control system processing units. Additional nodes can be added to the data highway to allow additional processing units, engineering work stations, and operator interface CRT's to be added to the control system.

f. Data link. The process 110 signals are connected to the termination units and through signal conditioners to the microprocessor controllers. The control system data highway for exchange of data between microprocessor based controllers and between microprocessor based controllers, data acquisition systems, operator interface and engineering work stations will be redundant. The data highways will utilize coax, twines of fiber optic cabling. The speed of data transmission is increasing and should be investigated prior to writing specifications. Data rates of approximately 1 mega baud are available.

9-2. Combustion controls.

a. General. The purpose of combustion control systems is to modulate the quantity of fuel and combustion air inputs to the boiler in response to a load index or demand (steam pressure or steam flow) and to maintain the proper fuel/air ratio for safe and efficient combustion for the boiler's entire load range.

b. System types. Three types of combustion control systems are available: series, parallel, and series-parallel. Each of these types are schematically represented in figure 9-1.

(1) *Series control.* A series control system as shown in figure 9-1(a) uses variation in the steam header pressure (or any other master demand signal) from the setpoint to cause a change in the combustion air flow which, in turn, results in a sequential change in fuel flow. The use of series control is limited to boilers of less than 100,000 pph that have a relatively constant steam load and a fuel with a constant Btu value.

(2) *Parallel control.* A parallel control system as shown in figure 9-1(b) uses a variation from setpoint of the master demand signal (normally steam pressure) to simultaneously adjust both the fuel and combustion air flows in parallel. This type of system is applicable to stoker-fired boilers, pulverized coal fired boilers, gas/oil fired boilers and atmospheric circulating fluidized bed (ACFB) boilers.

(3) *Series-parallel control.* A series-parallel control system as shown in figure 9-1(c) should be used to maintain the proper fuel/air ratio if the Btu value of the fuel varies by 20 percent or more, if the Btu input rate of the fuel is not easily monitored, or if both of these conditions are present. These conditions normally exist on pulver-

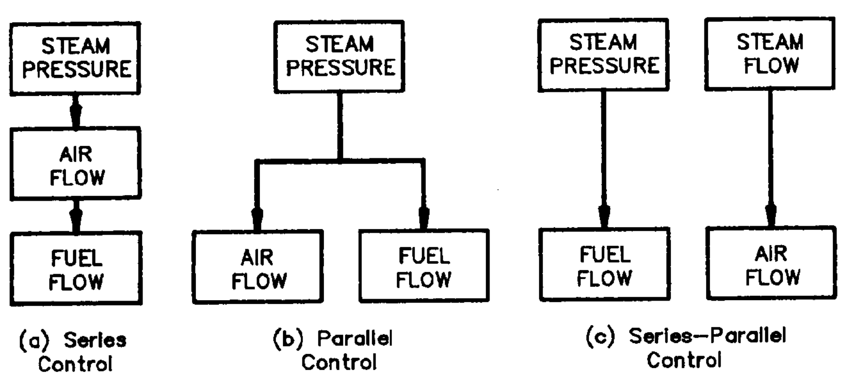

Figure 9–1. Types of Combustion Controls.

ized coal fired and ACFB boilers. Variations in the steam pressure setpoint adjust the fuel flow input. Since steam flow is directly related to heat release of the fuel, and because a relationship can be established between heat release and combustion air requirements, steam flow can be used as an index of required combustion air. Note however that this relationship is true only at steady load conditions.

c. System categories. Combustion controls can be further divided into two categories within the basic types: positioning control and metering control, as shown in figure 9-2.

(1) *Positioning control.* Positioning systems require that the final control elements move to a preset position in response to steam pressure variations from a setpoint. Series positioning control will not be covered here since it is only used on very small boilers operating at constant loads. Parallel positioning systems that use a mechanical jackshaft to simultaneously position fuel feed and air flow from a single actuator apply to packaged type gas/oil fired boilers in the 20,000 to 70,000 pph size and is shown in figure 9-2a. This system allows the operator to load the boiler over its complete operating range. The fuel valves and air damper are operated by the same drive through a mechanical linkage. The gas and oil valves include cams which are adjusted at start up to maintain proper fuel air ratio over the operating range of the boiler. Parallel positioning systems with fuel/air ratio control as shown in figure 9-2(b) are suitable for use on gas/oil and stoker fired units. This system allows the operator to adjust the fuel/air ratio for the entire load range of the boiler. The addition of steam flow correction of air flow to parallel positioning with fuel/air ratio control creates a system suitable for use on ACFB, gas/oil and pulverized coal fired units as shown in figure 9-2(c). This system uses variation of steam pressure from a setpoint to initially control fuel and air inputs. The system recorrects combustion air flow using steam flow as a setpoint for air flow, since steam flow is a function of fuel Btu input (inferred fuel flow). This system relates directly to a series-parallel type control with the addition of a feed-forward signal from the steam pressure controller to the combustion air control.

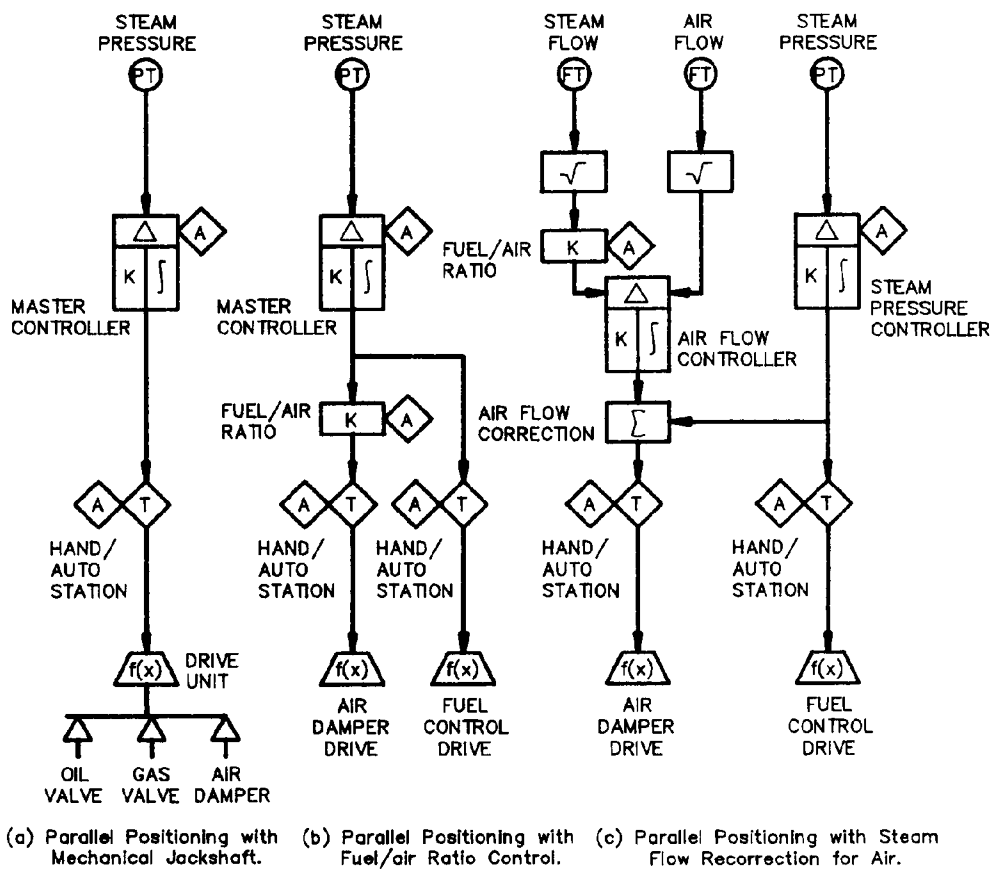

Figure 9–2. Positioning Controls.

(2) *Metering control.* Metering control systems regulate combustion based on metered fuel and air flows as shown in figure 9-3. The master demand developed from steam pressure error establishes the setpoints for fuel and combustion air flows at the controllers. The controllers drive the final control elements to establish proper fuel and flows which are fed back to the controllers. Maximum and minimum signal selectors are used to prevent the fuel input from exceeding available combustion air on a boiler load increase and to prevent combustion air from decreasing below fuel flow requirements on load reduction. This system is a cross-limiting flow tie back system with air leading fuel on load increase and fuel leading air on load reduction. This system is applicable to gas and oil, pulverized coal, and ACFB fired units.

d. System selection. Table 9-1 summarizes the combustion control systems discussed and their application to the various types of boilers.

e. Stoker system controls.

(1) *Fuel flow control.* The components of a stoker system must respond to the fuel flow demand signals generated by the combustion control system. For spreader stokers the coal feed to the overthrow rotor will vary with the demand signal. Grate speed on traveling grate and traveling chain grate stokers will respond to the demand signal. The frequency and duration of vibration cycles on vibrating grate stokers will vary with the demand signal. In all cases the relationship between fuel flow and unit load will be determined for use in the combustion control system to properly control fuel flow in response to the demand signal.

(2) *Combustion air control.* The combustion air flow is normally controlled at the FD fan. Two methods that are commonly used are control of inlet vanes on the FD fan or control of the FD fan inlet damper. If a metering control system is used the combustion air flow should be measured down

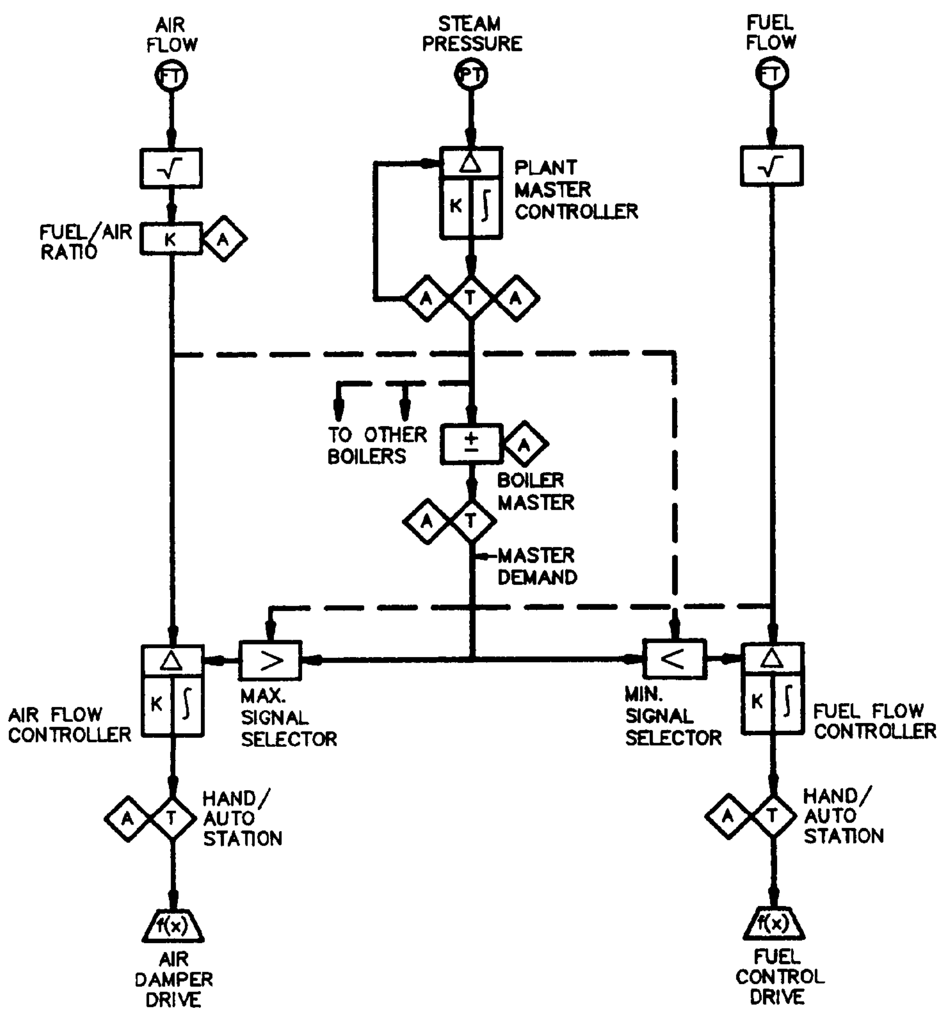

Figure 9–3. Metering Controls.

Table 9-1. Combustion Control System Selection Guide.

	Boiler Type				
Control System	*Gas/ Oil*	*Stoker*	*Pulverized Coal (PC)*	*Multiple Burner PC*	*ACFB*
Jackshaft positioning	X*				
Series control	X**	X**			
Parallel positioning	X	X			
Parallel positioning with steam flow correction of air	X	X	X		
Parallel metering with cross limiting and flow tie-back	X		X	X	

X Recommended Application

*Restricted to use on boilers 70,000 pph and under.

**Restricted to use on boilers under 100,000 pph with constant load and constant Btu value fuel.

stream from the fan outlet. The relationship between inlet vane or damper position and air flow will be determined for use in the combustion control system or for characterizing the final control element. Overfire air flow on stoker fired units normally is not measured. If overfire air is to be controlled the air flow demand signal will be used to control overfire air in parallel with combustion air.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is extremely important in combustion control systems for stoker fired boilers. A venturi section of air foil flow element should be provided in the ductwork between the FD fan and the stoker or a Piezometer ring may be installed at the FD fan inlet. The flow element will be designed to provide a design differential pressure across the flow element of not less than 2 inches wg at full load conditions. The flow transmitter selected for combustion air flow will be a differential pressure transmitter that is accurate in the range of differential pressure developed by the flow element.

f. Pulverized coal system controls.

(1) *Fuel flow control.* Fuel flow in pulverized coal systems is established by coal feeder inputs to the pulverizer. Coal feeder speed controls the fuel flow to the pulverizer. The volumetric rate of coal flow delivered to the pulverizer is directly related to feeder speed. Feeder speed varies with fuel flow demand.

(2) *Combustion air control.* Combustion air flow in pulverized coal systems consists of primary air flow and secondary air flow. Primary air is the air which transports the pulverized coal to the burner or burners. Secondary air is the air delivered by the FD fan to the boiler to support combustion. Total air flow is the sum of secondary air flow and all primary air flows. Secondary air is measured downstream of the FD fan and controlled by positioning FD fan inlet vanes or inlet damper. Primary air can be supplied by the FD fan or by a primary air fan. Primary air is normally measured on each pulverizer.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is essential for combustion control systems of pulverized coal fired boilers. Secondary air flow will be measured with a venturi section or air foil flow element in the ductwork between the FD fan and the boiler windbox. The flow element should be designed to provide a design differential pressure across the flow element of not less than 2-inches wg at full load conditions. Primary air flow will be measured on each pulverizer with a venturi section or pilot tube between the primary air fan and the pulverizer. The design pressure differential pressure across the primary air flow elements should not be less than 2-inches wg at full load. The transmitters selected for primary air flow and secondary air flow will be differential pressure transmitters that are accurate in the range of differential pressure developed by the flow elements.

(4) *Pulverizer controls.* Figure 9-4 shows one multiple pulverizer control scheme. In this arrangement the firing rate demand is compared to total fuel flow, which is the sum of all feeders to develop the demand to the pulverizer master. The pulverizer master demand signal is applied in parallel to all pulverizers which have duplicate controls. If an upset occurs in the fuel/air ratio such that total air flow is low, an error signal from air flow control reduces the firing rate demand to the pulverizer master to restore the proper fuel/air ratio. Since coal flow to the burner is a function of primary air flow the primary air damper and coal feeder speed control receive the same demand signal. If an error develops between demand and measured primary air flow or coal feeder speed, the controllers adjust the primary air flow or feeder speed to eliminate the error. If primary air flow is less than feeder speed demand, the feeder speed demand is made equal to the primary air flow by the low select auctioneer. A minimum pulverizer loading and a minimum primary air flow limit should be used to maintain the pulverizers above the minimum safe operating load to maintain adequate burner nozzle velocities and to maintain

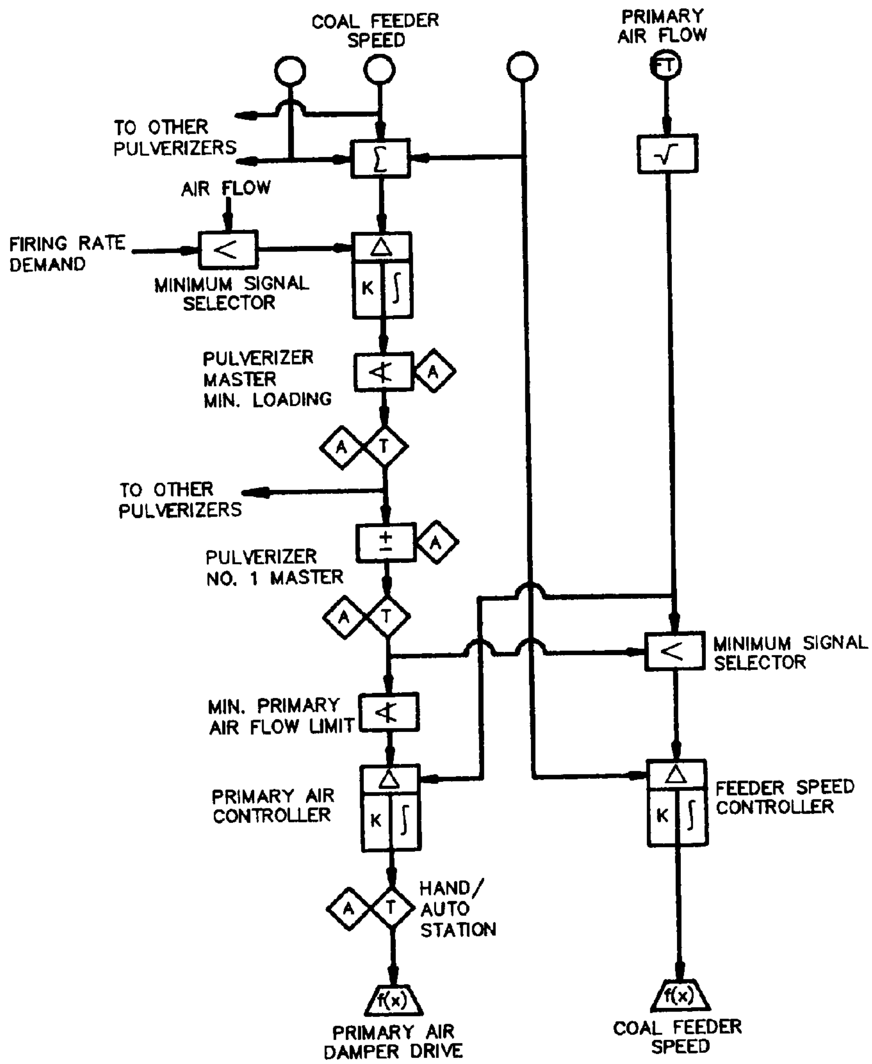

Figure 9–4. Pulverizer Controls.

the primary air to fuel ratio above a minimum level for all pulverizer loads.

g. Gas/oil system controls.

(1) *Fuel flow control.* Fuel flow in gas/oil fired boilers is controlled by operation of gas or oil control valves in the supply lines to the burners. The gas or oil control valves are modulated to control fuel flow based on the demand signal generated by the combustion control system. Gas flow to the burner is measured by taking the differential pressure across an orifice. Oil flow to the burners will be measured by a rotating disk type meter. Metering type control systems utilize the fuel flow and unit load in the combustion control system to properly modulate fuel flow in response to the system demand.

(2) *Combustion air control.* The combustion air is normally controlled at the FD fan. Air flow for package boilers is normally controlled by outlet dampers at the FD fan. Other methods that are used include control of the FD fan inlet vanes or control of the FD fan inlet damper. The relationship between inlet vane or damper position and air flow will be determined for characterizing the final control element. When a metering type control system is used air flow is measured downstream of the FD fan or a piezometer may be installed at the FD fan inlet.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is also important in metering type combustion control systems for gas/oil fired boilers. A venturi section or air foil flow element should be provided in the ductwork between the FD fan and the burner windbox or a piezometering may be installed at the FD fan inlet. The flow element will be designed to provide a design differential pressure across the flow element of not less than 2 inches wg at full load conditions. The flow transmitter selected for combustion air flow will be a differential pressure transmitter that is accurate in the range of differential pressure developed by the flow element.

(4) *Oil atomization.* The oil to the burner will be atomized utilizing steam or compressed air. A control valve installed in the atomizing steam or air line will be controlled to maintain the atomizing medium pressure above the oil supply pressure to the burner.

h. Atmospheric circulating fluidized bed (ACFB) boiler.

(1) *Fuel flow control.* Main fuel flow in an ACFB system is established by fuel flow through the feeder to the combustor. The volumetric rate of fuel flow is directly related to feeder speed. The coal feed demand speed utilizes the lower of the total air flow or firing rate demand as the set point and compares the set point to total fuel flow to develop the demand signal for the feeder master. The feeder master demand signal is applied to all feeders which have duplicate controls. Therefore, as firing rate demand is increased or decreased the feeder speed is increased or decreased. Coal chute air flow compares measured air flow to load flow to operate the coal chute air damper. A feed forward signal based on rate of change is also used to modulate the coal chute air control damper. Coal feeder and coal chute air damper control is shown in figure 9-5.

(2) *Combustion air control.* Combustion air flow in ACFB systems consists of primary air flow, overfire air flow, stripper cooler air flow, and main fuel chute air flow. Primary air is introduced below the bed and keeps the fuel and bed in suspension. Overfire air is delivered by the FD fan and is utilized at loads above 50 percent to control furnace exit gas temperature. The stripper cooler air flow is utilized to cool the excess bed material which is removed in the stripper section. Main fuel chute air flow is utilized to sweep the fuel tube to the combustor. Total air flow is the sum of primary air, overfire air, stripper cooler air, and coal chute air flow. All air can be supplied by the FD fan or separate primary air and FD fans may be utilized. The primary air, overfire air and stripper cooler are controlled by positioning the appropriate damper.

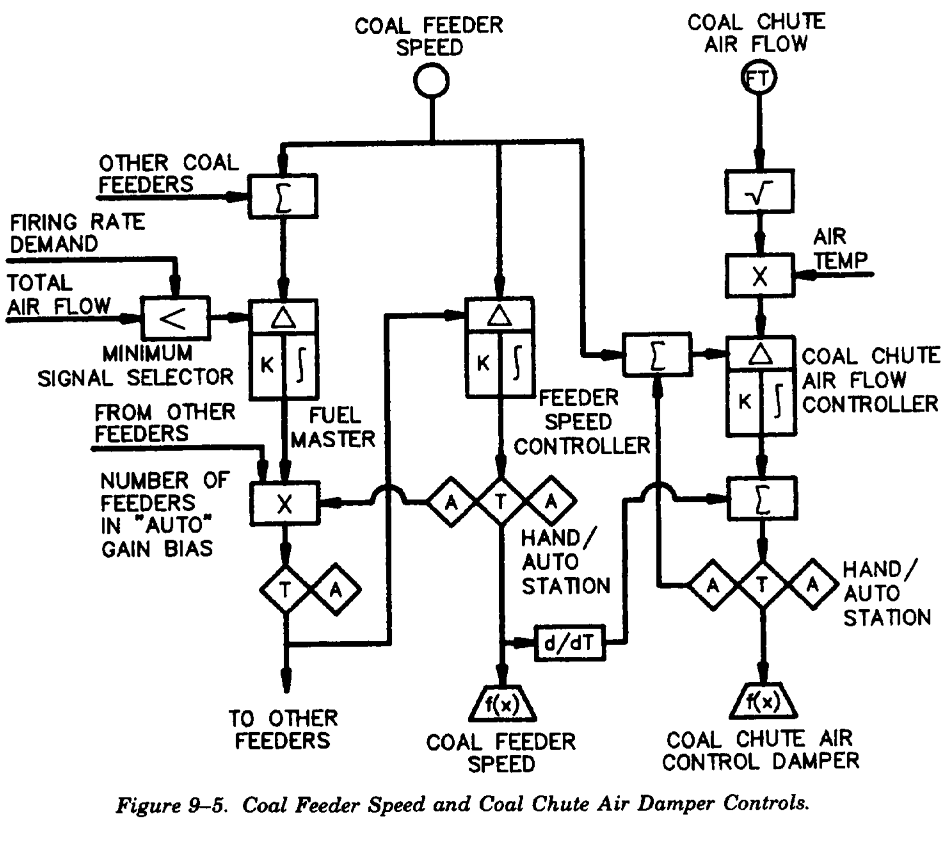

Figure 9-5. Coal Feeder Speed and Coal Chute Air Damper Controls.

Air supply is maintained by modulating the FD fan and primary air fan inlet vanes or dampers to maintain pressure in the FD fan outlet duct.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is also important in combustion control systems for ACFB boilers. Measurement of primary air flow, overfire air flow, stripper cooler air flow, and coal chute air flow will be measured with a venturi section or air flow element in the ductwork to the various equipment. The design pressure differential pressure across the air flow elements will be not less than 2-inches wg at full load. The transmitters selected for primary air flow and secondary air flow will be differential pressure transmitters that are accurate in the range of differential pressure developed by the flow elements.

(4) *Primary and overfire air flow control.* Figure 9-6 shows the primary and overfire air flow. The firing rate demand signal serves as an index for air flow demand. The fuel feed signal and firing rate demand signal are cross limited by a high selector to serve as the setpoint for the total air flow controller. The output of the total air flow controller becomes the setpoint for the primary and overfire air flow controllers. The setpoint is characterized based on load to obtain the proper primary-to-overfire air flow ratio. The upper overfire air dampers are closed below 50 percent load. The primary air controller setpoint is low limited by a minimum primary air setpoint. Each primary and upper air flow controller compares measured air flow to setpoint. The controller output becomes the demand to its respective air flow control damper. All air flow measurements should be temperature corrected. Furnace exit gas temperature should be monitored and at high temperature alarmed to allow the operator to make the proper air flow adjustment to bring the temperature back to normal. A bias adjustment normally is provided for each controller.

(5) *Furnace bed inventory control and solids cooler temperature, air flow and spray water control.* Furnace bed inventory control requires removal of excess bed material from the furnace. The solids cooler cools the excess bed material to a temperature which allows it to be disposed of via the ash system. Solids are removed from the furnace either by operator action or automatically on high furnace plenum pressure. The furnace bed static pressure, total furnace differential pressure,

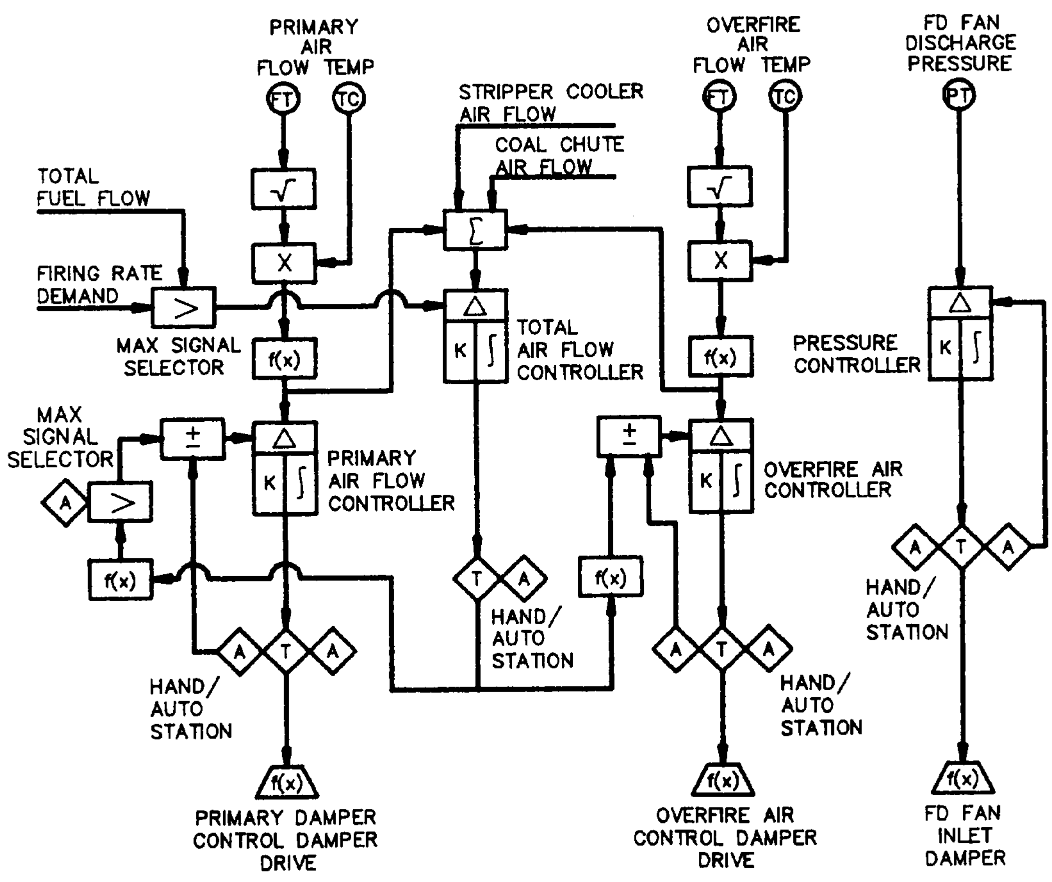

Figure 9-6. FD Fan Discharge Pressure, Primary and Overfire Air Controls.

furnace plenum static pressure and lower furnace differential are all monitored to give the operator an indication that the furnace bed inventory should be reduced. When a sequence for removal of materials is initiated the solids cooler air flow control dampers are opened to a preset position. The air flow dampers position will start a cycle timer and open the bed material transfer line. At the end of the timed period the transfer line is closed. The material is cooled by spray water and air flow to a temperature suitable for the ash system. The spray water valve opens and closes automatically based on cooler bed temperature. After the bed material is cooled it is placed in a hopper for removal by the ash system. The air flow dampers and solid spray water valve can be opened and closed manually by a hand auto station. Figure 9-7 shows the solids cooler temperature and flow control.

(6) *J-valve blower control.* The J-valve blower control maintains air flow for fluidization and transport of material from the hot cyclone to the furnace. The J-valve control is shown on figure 9-8. The system includes J-valve blower discharge-pressure control valve, upleg aeration and plenum control valve and downleg aeration and plenum control valves.

(a) J-valve pressure control. The J-valve blower pressure is maintained by sensing pressure downstream of the J-valve blower discharge damper. The discharge damper is modulated to maintain a constant pressure of approximately 170". The upleg and downleg plenum air is maintained at a constant value of approximately 400 lb/hr. The setpoint is constant throughout the load range. Upleg and downleg plenum air flow will be measured with a Venturi section or air foil flow element in the ductwork to the plenums. The flow element will be designed to provide a design differential pressure across the flow element of not less than 2 inches wg.

(b) J-valve aeration valve control. The measured air flow is compared to the constant setpoint and the control dampers modulated to maintain the air flow at setpoint. The downleg static pressure, inlet static pressure, and upleg static pressure outlet as well as differential pressure across portions of the J-valve indicate solids flow, density and dipleg differential are measured and are utilized to allow the operator to manually control

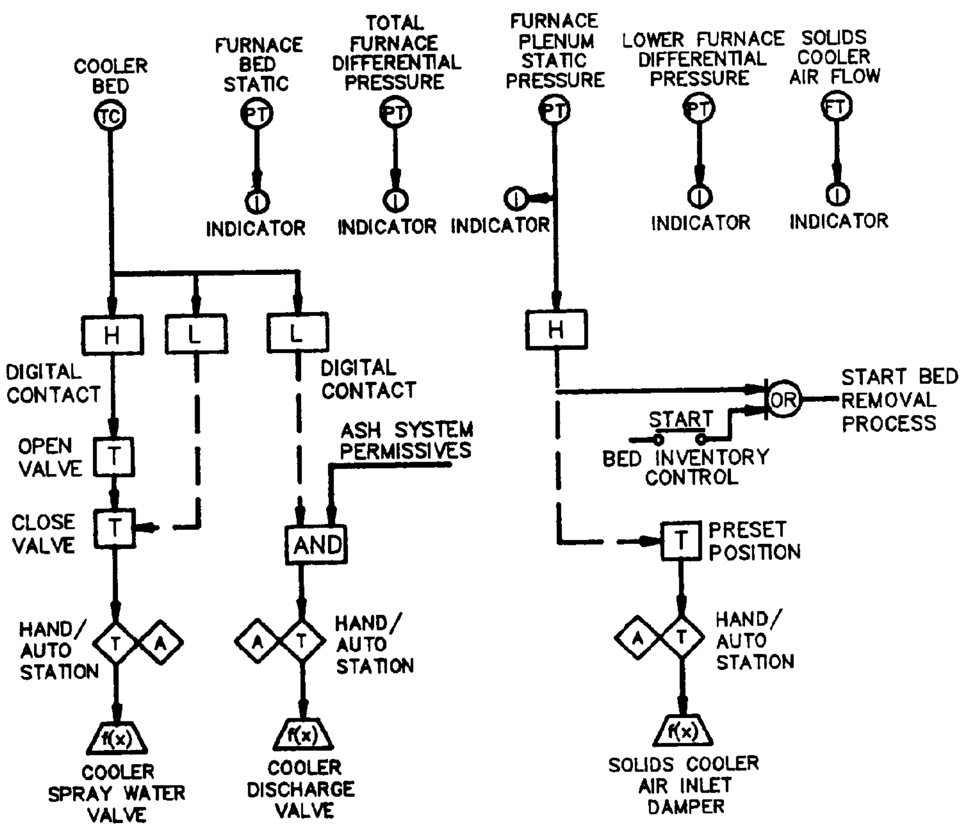

Figure 9-7. Bed Inventory and Solids Cooler Controls.

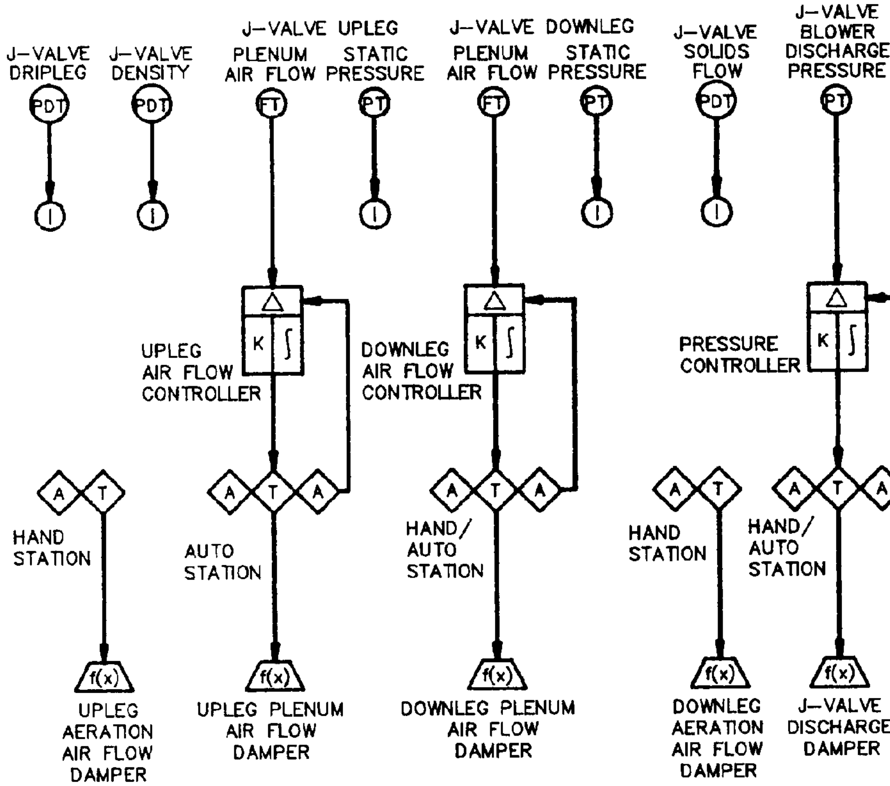

Figure 9–8. J-valve Controls.

the aeration valves. The aeration control is normally only required during start-up and are manually controlled.

(7) *Sorbent (limestone) feeder control.* The sorbent feeder control provides the proper amount of sorbent to capture the SO_2 generated in the combustion process. The sorbent feeder control is shown in figure 9-9. Sorbent feeder speed controls the sorbent flow to the combustor. The volumetric rate of sorbent delivered to the combustor is directly related to feeder speed. Feeder speed setpoint is based on SO_2 in the stack flue gases, modified by oxygen in the flue gas, total fuel flow and a correction factor. The SO_2 measurement is provided by a flue gas analyzer or analyzers, total fuel flow is taken from the main fuel feeders and oxygen from the flue gas O_2 analyzer. The setpoint value is compared to the actual sorbent (limestone) flow. A low limit is applied to the controller output to prevent the value from falling below a minimum value.

(8) *Warmup burner control.* A gas/oil fired burner or in-bed lances are utilized to warm the bed material to the value where main fuel combustion occurs. When gas/oil fire burners are utilized they normally are placed in the primary air duct. Fuel flow is regulated by a controller comparing primary air temperature at the burner outlet to the selected temperature. A low limit select limits the fuel to the available primary air flow through the duct burner. When in-bed lances are utilized the fuel flow setpoint is compared to the actual fuel flow to modulate the burner valve. Position of the fuel valve is limited by a low selector to the available air flow to the combustor. The warmup burner and in-bed lance control is shown in figure 9-10.

i. Oxygen trim. Boiler efficiency can be improved by minimizing excess air levels. Excess air is required to ensure complete combustion and optimum heat release from the fuel. However excess air adds to heat loss and reduces boiler thermal efficiency. Oxygen trim controls are used to operate the boiler at low excess air levels. An oxygen analyzer is installed to monitor the amount of oxygen in the boiler flue gas. The signal from the analyzer is used to correct the combustion air flow to maintain the proper oxygen level in the flue gas exiting the boiler. The boiler manufacturer's recommendations for flue gas oxygen content versus boiler load for optimum boiler efficiency should be used to establish the proper oxygen content in the flue gas at all boiler loads. Oxygen trim controls applied to a parallel metering system

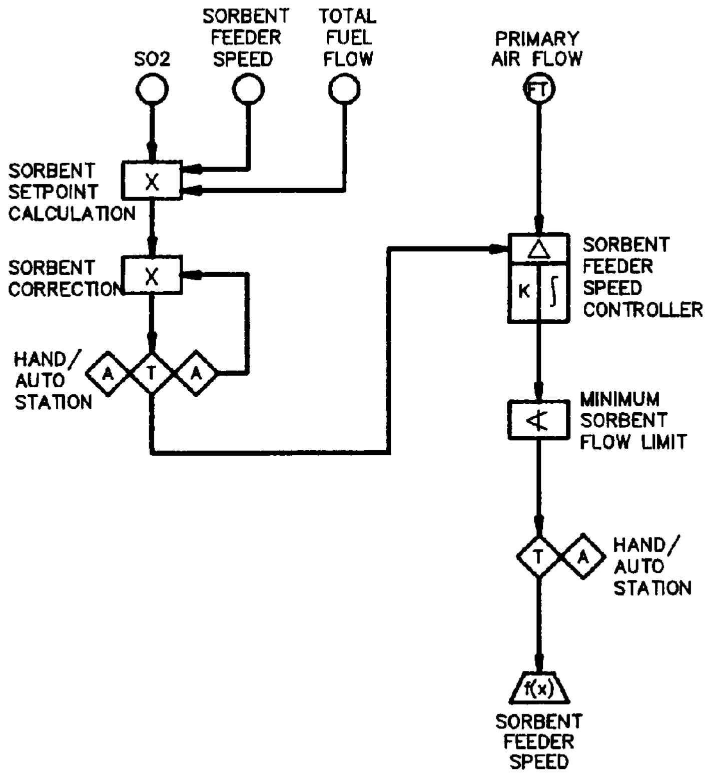

Figure 9–9. Sorbent Feeder Controls.

are shown in figure 9-11. The oxygen setpoint is calculated from boiler load by a characterizing function generator applied to steam flow. Signal limiters are used to establish minimum and maximum corrections to the fuel/air ratio since major excursions are possible due to malfunctions of the oxygen analyzer. Automatic oxygen trim controls should not be used on stoker fired units. Since the fuel bed on a stoker cannot be increased or decreased quickly the firing rate on a stoker is varied primarily by changes in combustion air flow. Changes in combustion air flow will cause similar changes in flue gas oxygen content. Automatic oxygen trim would attempt to correct the air flow and would cause unstable operation during load changes. Stoker fired units should be provided with manual oxygen trim.

9-3. Boiler controls.

a. Furnace safety system.

(1) *General requirements.* The main function of a furnace safety system is to prevent unsafe conditions to exist in the boiler including prevention of the formation of explosive mixtures of fuel and air in any part of the boiler during all phases of operation. The system must be made to comply with the appropriate NFPA regulations and the recommendations of the boiler manufacturer.

(2) *Purging and interlocks.* The specific purging and interlock requirements will depend on whether the boiler is gas/oil fired, stoker fired, pulverized coal fired or ACFB fired. Regardless of the type of firing system, certain functions must be included in the furnace safety system. These functions include a prefiring purge of the furnace, establishment of permissives for fuel firing, emergency shutdown of the firing system when required, and a post firing purge. Pulverized coal, ACFB and gas/oil firing require additional functions such as establishment of permissives for firing the ignition system and continuous monitoring of firing conditions. The prefiring purge is required to ensure that all unburned fuel accumulated in the furnace is completely removed and is accomplished by passing a minimum of 25 to 30 percent air flow through the furnace for five minutes. The conditions that would cause an emergency shutdown (trip) for pulverized coal, gas/oil and ACFB boilers are shown in table 9-2. The furnace safety system can be either deenergize-to-trip to

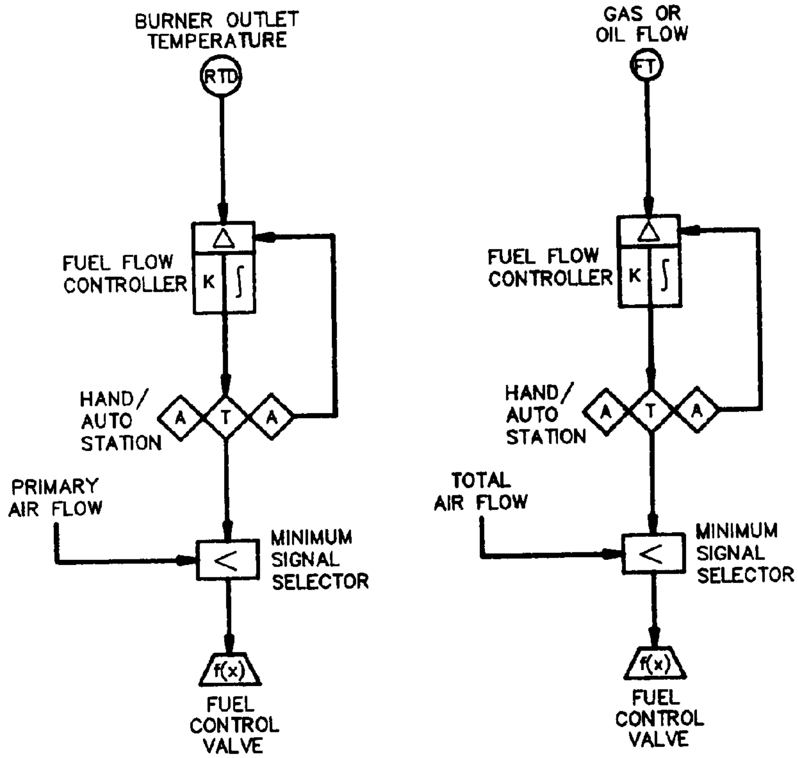

Figure 9–10. Bed Warm-up Controls.

energize-to-trip. The energize-to-trip philosophy is more desirable since it reduces nuisance trips, is operable on loss of power, and is more reliable.

(3) *Flame detection and management.* Stoker fired boilers do not utilize flame detection or flame management. Pulverized coal and gas/oil fired systems do require flame detection, which is the key to proper flame management. The basic requirements of flame detectors are detection of the high energy zone of a burner flame, ability to distinguish between ignitor and main flames, and discrimination between the source flame, adjacent flames, and background radiation. Ultraviolet (UV) detectors are suited for flame detection of gas or light oil ignitor and main gas flames. Infrared (IR) detectors are used for pulverized coal flames. Self checking or redundant detectors should be used to ensure reliability. Location of the flame detectors is critical to proper flame management and must be given careful consideration. Flame detection systems will be on-off type based on the presence or absence of flame.

(4) *Burner controls.* Burner controls are the permissives, interlocks, and sequential logic which are required for safe startup and operation of pulverized coal, ACFB and gas/oil burners. Burner controls range from manual to fully automatic. Regardless of the level of automation incorporated into the burner controls, the system logic must insure that the operator commands are performed in the correct sequence with intervention only when required to prevent a hazardous condition. Pulverized coal burner controls must provide the proper sequential logic to completely supervise burner startup and operation including coal feeders, pulverizers, air registers, ignitors, and flame detectors. Gas/oil burner controls must provide the proper sequential logic to completely supervise burner startup and operation including gas/oil fuel valves, air registers, ignitors and flame detectors. The ACFB boiler includes utilizing a main gas burner or gas lances and ignitor system to warm the boiler and bed temperature above minimum required for solid fuel firing. This burner operation is identical to a gas/oil burner operation. The ACFB boiler does not have a main fuel burner; however, the introduction of fuel is completely supervised to provide the proper sequence for purge, ignitors, warm-up burners, flame detection, coal feeders, sorbent feeders and bed temperature monitoring. Note the bed temperature monitor insures that adequate temperature is present to ignite the solid fuel. Adequate bed temperature

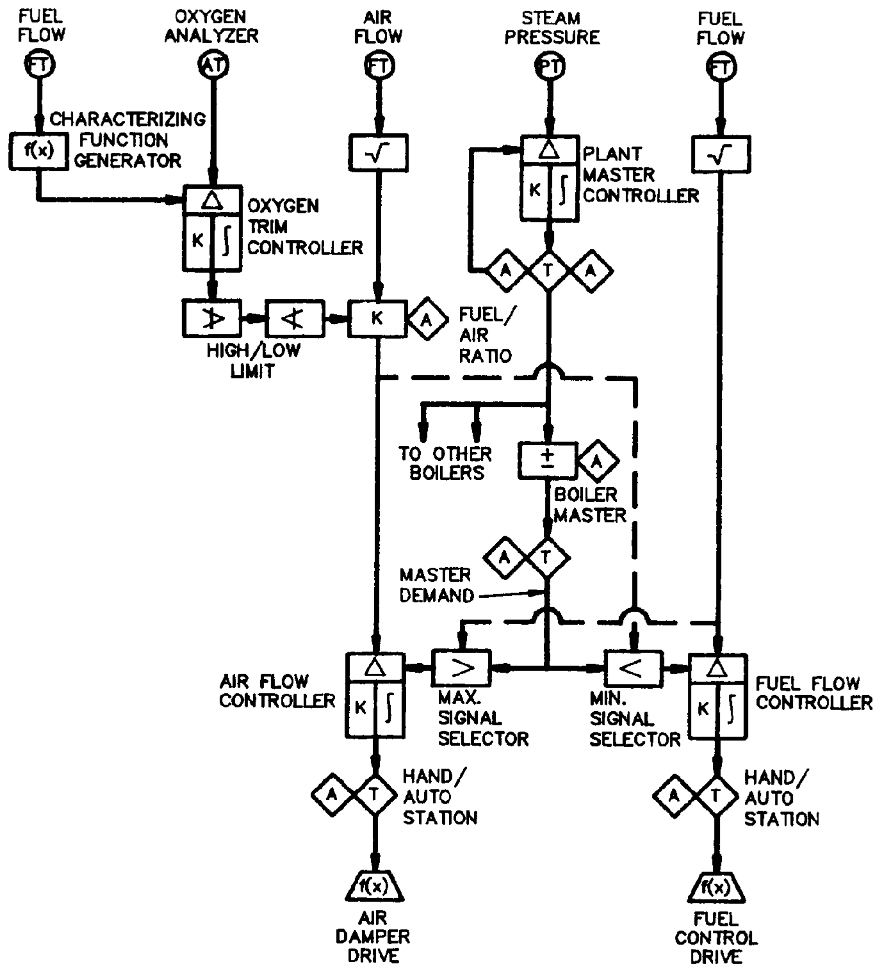

Figure 9–11. Oxygen Trim Controls for Parallel Metering Control.

Table 9-2. Emergency Trip for Boilers.

Item	*Pulverized Coal*	*Gas/Oil*	*ACFB*
Loss of all FD fans	X	X	X
Loss of all ID fans (if used)	X	X	X
High-low drum level	X	X	X
High steam pressure	X	X	X
High furnace pressure or draft	X	X	X
Low air flow	X	X	X
Loss of power to safety system	X	X	X
Flame failure	X	X	
Gas or oil pressure/temperature out of limits		X	
High cyclone level			X
All solids fuel feeders trip	X		X
Bed temperature greater than maximum			X
Bed temperature less than minimum			X
Emergency trip pushbutton	X	X	X
Trips recommended by boiler supplier	X	X	X

allows a hot restart which bypasses the purge, ignitors and warm burners and allows the introduction of solid fuel provided certain conditions are met. Figure 9-12 shows sequential logic for burner control.

b. Feedwater flow and drum level control.

(1) *Two element control.* Two element feedwater control systems as shown in figure 9-13(a) are characterized by the use of steam flow as a feed-forward signal to reduce the effect of shrink and swell of the boiler drum level during load changes. Without the steam flow feed-forward signal, load changes will momentarily cause the drum level to change in a direction opposite to the load change. The feed-forward signal provides the correct initial response of the feedwater valve.

(2) *Three element control.* Three element feedwater control as shown in figure 9-13(b) uses feedwater flow in addition to steam flow to improve drum level control. In this system feedwater

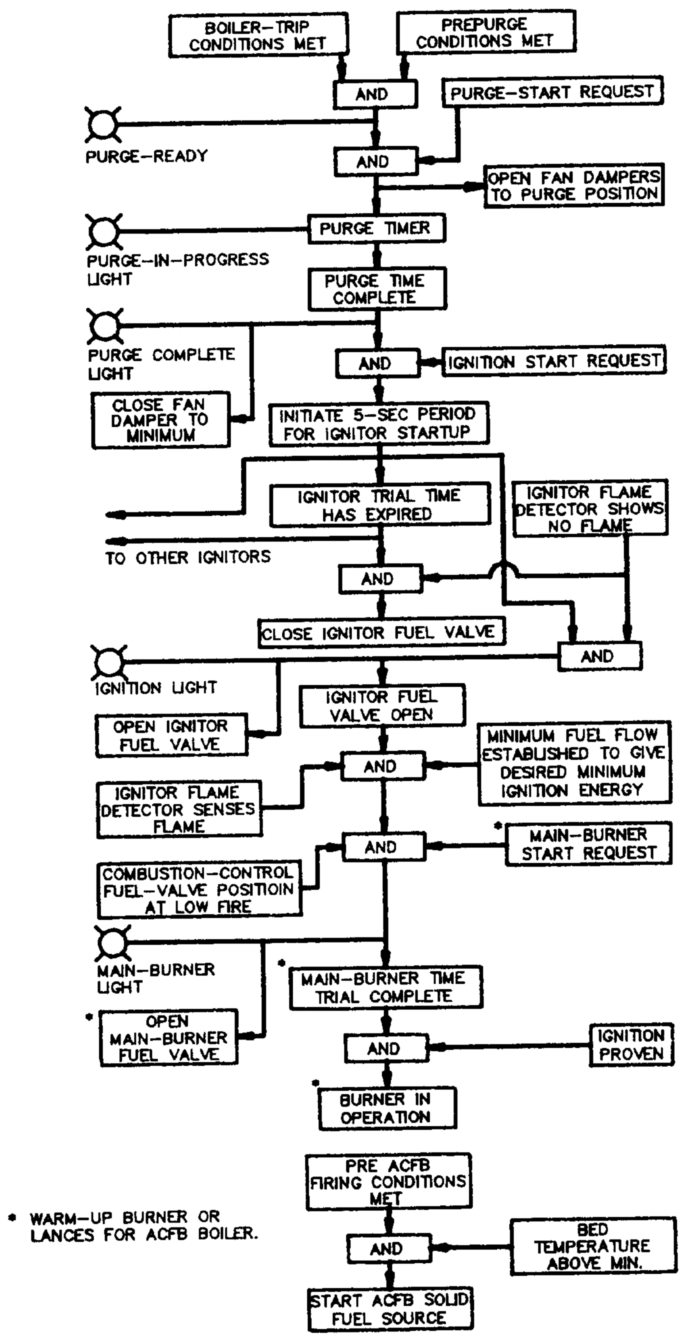

Figure 9–12. Burner Control Sequence.

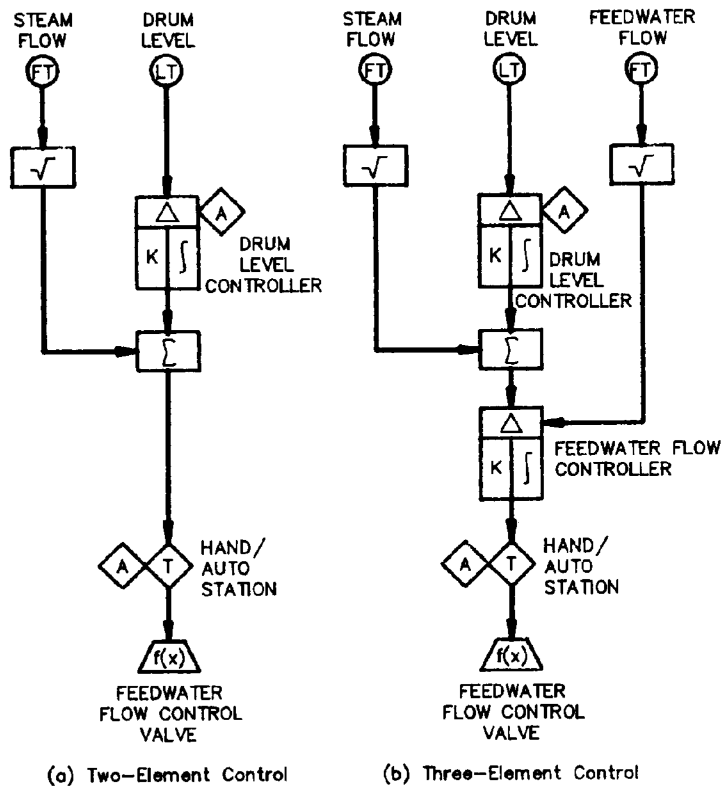

Figure 9–13. Feedwater Control System.

flow to the boiler is metered and the feedwater valve is positioned by summing steam flow and drum level error through a controller. This system should be used when multiple boilers are connected to a common feedwater supply system since feedwater flow is a metered feedback signal and the control system demands a feedwater flow.

(3) *System selection.* Table 9-3 summarizes the types of feedwater control systems and the parameters which should be used for selection of the proper system.

c. Furnace pressure controls.

(1) *Single element control.* Furnace pressure controls are primarily single element type. The final control element is the ID fan inlet damper, ID fan inlet vanes or adjustable speed drive for ID fan. The control loop shown in figure 9-14 also uses a feed-forward demand signal that is representative

Table 9-3. Feedwater Control System Selection Guide

	Boiler Requirements		
Control System	*Steady-State Load*	*Swinging Load*	*Multiple Boiler*
Two-element	X	X	
Three-element		X	X

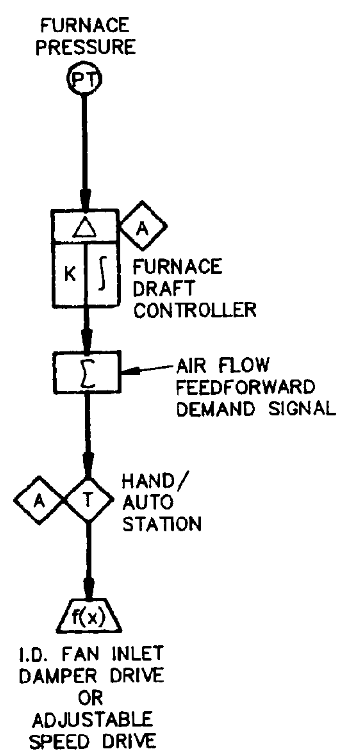

Figure 9–14. Single Element Furnace Pressure Controls.

of boiler air flow demand. This feed-forward signal may be fuel flow, boiler master, or other demand index, but will not be a measured air flow signal.

(2) *Furnace implosion protection.* Boilers that have a large capacity and large draft losses due to air quality control equipment may require ID fans with a head capacity large enough to exceed design pressure limits of the furnace and ductwork. If this possibility exists, the furnace pressure control system must include furnace implosion protection. The furnace implosion protection system will comply with the guidelines established by NFPA 85G. These guidelines include redundant furnace pressure transmitters and transmitter monitoring system, fan limits or run-backs on large furnace draft error, feed-forward action initiated by a main fuel trip, operating speed requirements for final control elements, and interlock systems.

d. Steam controls.

(1) *Steam pressure control.* Steam pressure is controlled by boiler firing rate. As discussed in combustion control, steam pressure is used to establish the master demand signal that controls fuel and combustion air flow.

(2) *Steam flow control.* Steam flow is a function of boiler load demand. Steam flow is also a function of fuel Btu input and can be used to trim combustion air flow as discussed in combustion control. Steam flow is also used to calculate boiler load for use in oxygen trim controls and as a feed-forward signal in feedwater controls.

(3) *Steam temperature control.* Boilers that produce saturated steam do not require steam temperature controls. Boilers that produce superheated steam require a control loop to maintain superheater outlet temperature. A single element loop with feedback as shown in figure 9-15 is normally adequate for control of steam temperature.

e. Blowdown controls.

(1) *Continuous blowdown.* Continuous blowdown is the continuous removal of concentrated water from the boiler. The rate of blowdown is controlled by manually adjusting the setting of the continuous blowdown control valve. Continuous blowdown can be used on boilers of any capacity and permits heat recovery of the blowdown. The use of continuous blowdown heat recovery is dependent upon life cycle cost evaluation.

(2) *Automatic blowdown.* Automatic blowdown systems as shown in figure 9-16 continuously monitor the boiler water and adjust the rate of blowdown to maintain the conductance of the boiler water at the proper level. Control action can be two-position or modulating. The use of automatic blowdown will be dependent on whether blowdown heat is to be recovered and a LCCA.

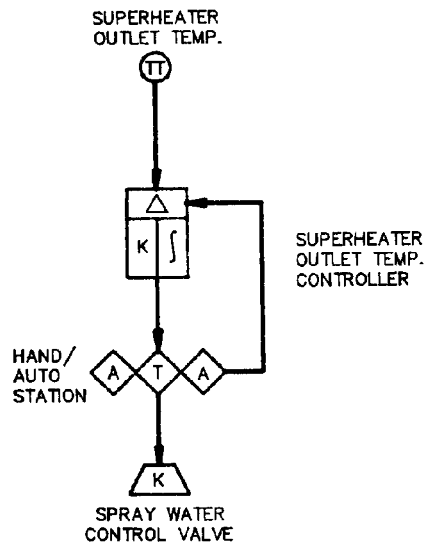

Figure 9–15. Single Element Steam Temperature Controls.

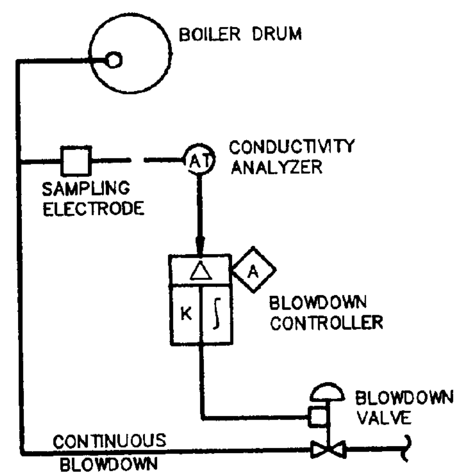

Figure 9–16. Automatic Blowdown Controls.

f. Sootblower control. Sootblower control should be an operator-initiated automated sequence control. After the start command the system should step through the sequence for all sootblowers including opening the valve for the sootblowing medium, timing the length of the blow and closing the valve. The system should automatically move to the next sootblower and continue the sequence until all sootblowers have been completed.

9-4. Nonboiler controls.

a. Low pressure steam controls.

(1) *Turbine drives.* The boiler feed pump turbine drive is controlled by feedwater header pressure. The steam control valve on the turbine drive inlet is controlled by a pressure transmitter on the feedwater header acting through a controller as shown in figure 9-17. The setpoint pressure will be lower than the normal operating feedwater pressure to prevent turbine drive operation during normal operating conditions.

(2) *Sootblowers.* Sootblower steam controls are normally a pressure control system to maintain the proper steam pressure at the sootblower inlet. If remote indication of the sootblower steam header pressure is desired a transmitter and controller will be used as shown in figure 9-18(a). If remote indication is not required a pressure controller mounted on the control valve can be used as shown in figure 9-18(b).

(3) *Steam coil air heater.* The steam coil air heater controls are based on maintaining the flue gas leaving the air heater above the acid dew point temperature. This is accomplished by using an average cold end temperature control system as shown in figure 9-19. Air heater average inlet air temperature and average gas outlet temperature are calculated. These two signals are averaged to arrive at the average cold end temperature, which is used to control the steam coil control valve. Also, the control system should include an interlock that opens the steam coil control valve 100 percent when the ambient air is below a set temperature, usually 35 degrees F.

(4) *Deaerator.* The DA steam controls are a pressure control system to maintain DA pressure. A single element loop with feedback as shown in figure 9-20 is adequate for controlling DA pressure.

(5) *Feedwater heater.* The feedwater heater controls as shown in figure 9-21 are used to protect the economizer against acid condensation. The economizer outlet gas temperature and economizer inlet feedwater temperature are averaged. The average is used to control the feedwater temperature by regulating the steam input to the feedwater heater.

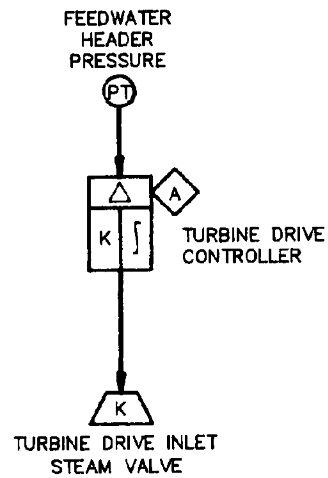

Figure 9–17. Turbine Drive Controls.

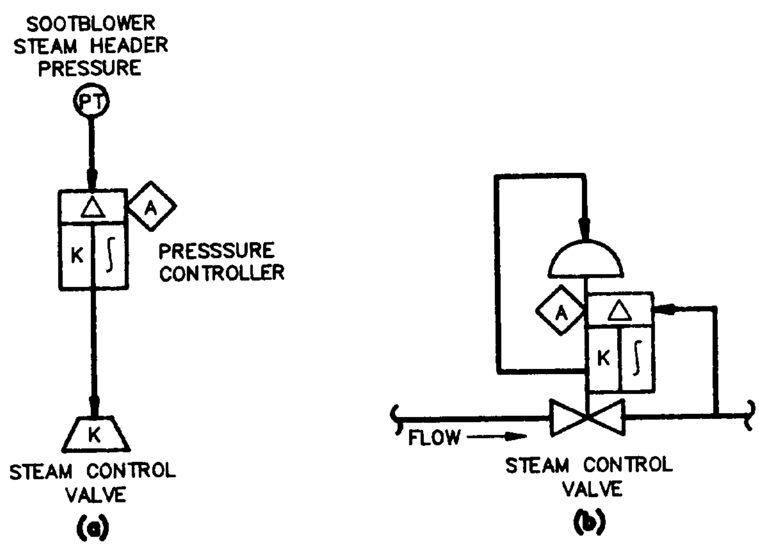

Figure 9–18. Sootblower Steam Controls.

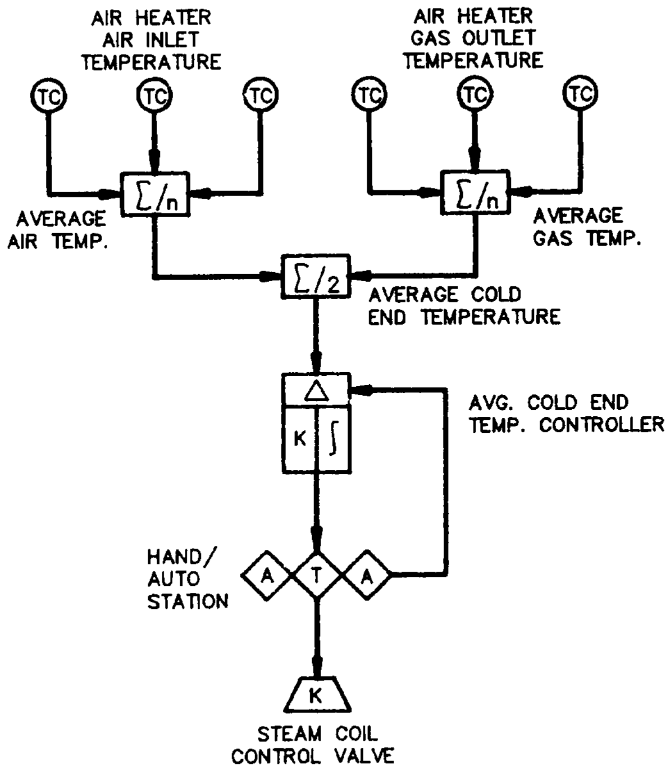

Figure 9–19. Steam Coil Airheater Controls.

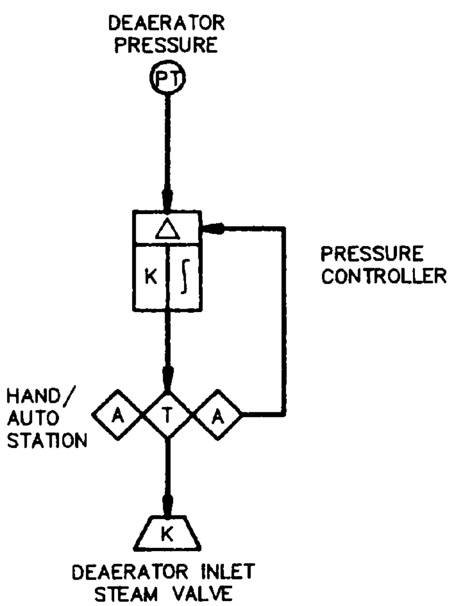

Figure 9–20. Deaerator Steam Controls.

b. Deaerator level controls.

(1) *Two element control.* A two element DA level control system as shown in figure 9-22(a) uses feedwater flow as a feedwater signal to make the system responsive to load changes. A two element system for DA level control can be used for most multiple unit installations that operate under steady load conditions.

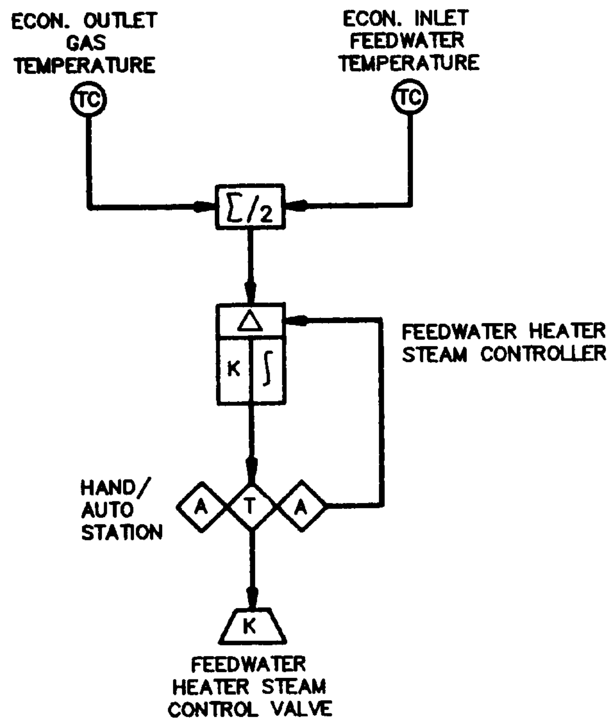

Figure 9–21. Feedwater Heater Controls.

(2) *Three element control.* A three element DA level control system as shown in figure 9-22(b) uses a metered condensate flow feedback signal in a cascaded control loop. This system will maintain DA level on units that operate under swinging load conditions.

c. Pump recirculat ion control. Pump recirculation controls are necessary to maintain the minimum flow through a pump when required by the manufacturer. A breakdown orifice plate sized to pass the required minimum flow can be installed in a line from the pump discharge to the pump suction source. Since this system is a constant recirculation type, it is a source of lost pump hp. The lost hp can be eliminated by using automatic pump recirculation controls. This system requires pump flow to be metered and an automatic valve to open when pump flow is at or below the minimum flow requirement. Automatic recirculation control will be used only when justified by LCCA evaluation.

9-5. Control panels.

a. Control room. A control room isolated from the plant environment complete with heating and air conditioning should be provided for all boiler plants. The boiler panels and auxiliaries may be located at the boiler front for packaged boilers up to 70,000 pph and for stoker fired units. A recorder panel should be located in the control room. The

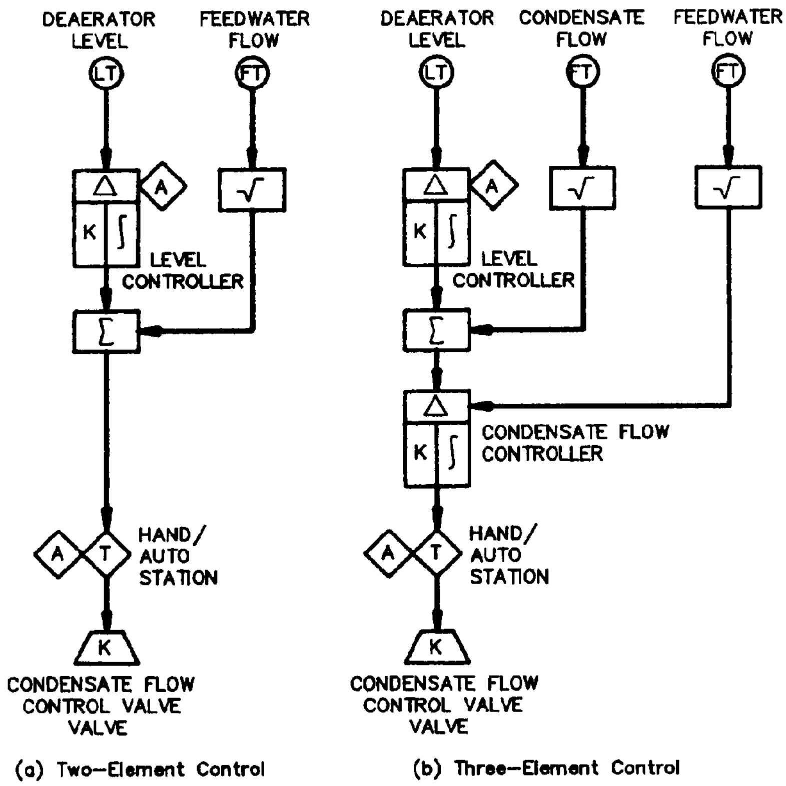

Figure 9–22. Deaerator Level Controls.

control room will be located at a central location in the plant to allow operating personnel good access to the boilers and the auxiliary equipment. The control room will be large enough for the operator interface for the boiler and auxiliaries and also allow room for a desk to be used by operating personnel.

b. Operator interface. The operator interface to the boiler and auxiliaries may be via CRT's and printer housed in a control console or operator stations, recorders, indicators, annunciators and start/stop controls mounted on a control panel.

(1) *Distributed control system.* Operator interface via CRT and printers are normally used on larger units and are part of the distributed control system. This system should always utilize redundant microprocessors, ORT's and printers. The system will automatically switch to the back-up system and annunciate failure of a component. The system will be utilized to perform combustion control, data acquisition and trending, boiler efficiency calculations, graphic displays, boiler control motor start/stop and ash system controls. An auxiliary panel will also be required to mount critical controls and monitoring equipment.

(a) I/O racks. The system will include remote mounted input/output racks with redundant microprocessors for control. The information at the I/O rack will be multiplexed to allow communication with other I/O racks and the central control console. Redundant communication links should be provided to allow communication when one link is lost. All field wiring entering or leaving the I/O racks is to be connected to terminal blocks with spare terminals provided. The equipment in the 110 racks will be designed for installation in a dusty atmosphere with maximum ambient temperatures of 50 degrees C.

(b) Operator interface. The control console will include the appropriate number of CRT's and printers required by the size and complexity of the system. A minimum of two CRT's and two printers should be installed. The CRT's and keyboard or other means of operation will be mounted in a console which allows the operators to access and operate the controls while sitting at a chair in front of the CRT.

(c) Auxiliary panel. Auxiliary panel construction must conform to the requirements of the National Electrical Code, the National Fire Protection Association, and NEMA standards. It will be constructed of steel plate with adequate internal reinforcement to maintain flat surfaces and to provide rigid support for the instrumentation to be installed. The panel interior will have adequate bracing and brackets for mounting of equipment to be installed within the panel. Electrical outlets will be provided in the panel. No pressure piping of

process fluids is to be run in control panels. All field wiring entering or leaving control panels is to be connected to terminal blocks with spare terminals provided. The items to be mounted in the auxiliary panel will include hardwired main fuel trip (MFT) pushbutton, fan trips, drum level indication, soot blower controls and annunciation of critical items. The annunciator should include items listed below.

1. Main fuel trip (MFP)
2. Drum level high-low.
3. Furnace pressure high.
4. Boiler FW pressure low.
5. Control system power failure.

(2) *Panel mounted control system.* The control and auxiliaries panel where used will include operator stations, recorders, indicators, equipment start-stop controls and annunciation. The arrangement of the panel will not be addressed here since panel arrangements are normally based on the preferences of operating personnel and management.

(a) Control panel construction. Control panel construction must conform to the requirements of the National Electrical Code, the National Fire Protection Association, and NEMA standards. Panels will be constructed of steel plate with adequate internal reinforcement to maintain flat surfaces and to provide rigid support for the instrumentation to be installed. The panel interior will have adequate bracing and brackets for mounting of equipment to be installed within the panel. A walk-in door for access to the panel interior will be provided on both ends of the panel where possible and on at least one end of the panel. Electrical outlets will be provided in the panel. No pressure piping of process fluids is to be run in control panels. All field wiring entering or leaving control panels is to be connected to terminal blocks with spare terminals provided.

c. Instrumentation requirements. The boiler and auxiliaries panel or control console will provide operator interface required to properly control and monitor the operation of the boilers and auxiliary equipment in the steam plant. This will include operator interface to stations, recorders or trending, indication, equipment start/stop controls, and annunciation. Table 9-4 summarizes the instrumentation requirements for the operator interface.

(1) *Operator stations.* Operator stations are to be provided as shown in table 9-4. Operator stations on control consoles will be accessed through the CRT or through individual operator station on control panels. Hand automatic operator stations will provide bumpless transfer from hand to automatic and automatic to hand without manual balancing for transfer; and have antireset windup characteristics. Operator stations with set point will indicate set point in engineering units. Operator stations with ratio or bias are to indicate the magnitude of the ratio or bias at all times. Operator stations are to indicate the measured variable on a continuously in engineering units and will indicate station output continuously in percent. The indications on a station should be consistent with all other stations such that all final control elements move closed to open from zero to 100 percent. For hardwired operator stations, the position of final control elements will not change when an operator station is disconnected from or reconnected to its plug-in cable. Changes in ratio or bias settings will not cause a process upset.

(2) *Records.* Records will be kept for the parameters indicated in table 9-4. Records will be stored on floppy disks when a control console is used. The operator will have access through the CRT to display trends for parameter for which records are kept. When the operator interface utilizes boiler and auxiliaries panels recorders will be used. Recorders may be strip chart recorders or circular chart recorders. The recorders will have scale markings consistent with the measured variables and associated field transmitters. The use of circular chart recorders will be restricted to steam pressure, steam flow, air flow, and exit gas temperature. Circular chart recorders will not be used when conservation of panel space is critical or desirable. Allowances should be made to provide spare pens for future use.

(3) *Indicators.* Indicators will be provided for the parameters shown in table 9-4. When a control console is utilized the parameter will be displayed on the CRT. The display may be digital or graphic and the displays should have scale markings consistent with the measured variable and associated field transmitter. When indicators are located on a panel the indicators may be digital indicators or analog indicators. Digital indicators will have Light Emitting Diode (LED) uniplaner numerals, zero instrument zero drift with time, and 0.1 percent Full Scale (FS) or less span drift per year. Analog indicators will have vertical edgewise scales, plus or minus 2 percent full scale accuracy, and scale markings consistent with the measured variable and the associated field transmitter. Integrators are shown in table 9-4 and should include the signal converters necessary to provide scaled integrated readings. Integrators will have at least six digit readout.

(4) *Equipment start/stop controls.* Equipment start/stop controls will be provided for all major

equipment as shown in table 9-4. Start/stop controls on a control console will be performed utilizing the ORT. Indication of motor operation should be indicated on the CRT. Start/stop controls will be indicating control switches or indicating push button when boiler and auxiliary panels are used for the operator interface.

(5) *Annunciator.* Annunciators will be provided on the boiler and auxiliaries panel for visual and audible indication of alarm conditions. Annunciator windows will have alarm legends etched on the windows and will be backlighted in alarm or test state. Each window will have at least two parallel connected bulbs and front access for ease of bulb replacement. All annunciator circuits will be solid state and compatible with microprocessor based controls. The annunciator will have an adjustable tone and volume horn. Split windows will be avoided unless conservation of panel space is critical. The annunciator system will have one of the alarm sequences specified in Instrument Society of America (ISA) S18.1. Test and acknowledge pushbuttons will be provided on the panel. All alarms, except for critical alarms, will be displaced on the ORT and printed on the printer when CRT's are utilized as the operator interface.

d. Ash handling control for stoker, pulverized coal and ACFB boilers.

(1) *General requirements.* Control of the fly ash system will be from the control room via ORT or control panel. A bottom ash panel will be located near the boilers. The control of the bottom ash system may also be controlled from the control room. The operator interface will contain all devices required to properly control and monitor the operation of the ash handling system. This will include start/stop control, selector controls, indication, and annunciator.

(2) *Start/stop controls.* Controls will include start/stop controls for the vacuum producing equipment, initiation of system operation, emergency stop, selection of manual or automatic system operation and manual operation of hopper valves and vibrators. This control may be through a CRT or panel mounted indicating control switches or indicating pushbuttons, pushbuttons and selector switches.

(3) *Indicators.* Indication of system vacuum, primary and secondary bag filter pressures and temperature and vacuum pumps inlet temperature, valve position, bag filter operation, system operation and hopper being emptied should be displayed in the control room. The display may be via CRT or panel mounted indicators and indicating lights.

(4) *Annunciation.* Alarm conditions of the ash handling system should be audible and visually annunciated in the control room. Annunciation may be via CRT and printer or a panel mounted annunciator of the same type described in c(5) above.

f. Air quality control system for stoker, pulverized coal and ACFB boilers.

(1) *General requirements.* Control of the air quality control equipment will be from the control room via CRT or control panel. The operator interface will contain all devices required to control and monitor the operation of the air quality control system. This will include start/stop controls, selector controls, indication and annunciation.

(2) *Start-stop controls.* Start/stop controls will be provided for manual operation of baghouse cleaning via the CRT or panel mounted control switches.

(3) *Selection controls.* Selection controls will be provided for selection of manual, pressure initiated, or time sequenced baghouse cleaning. Operation of compartment isolation dampers and baghouse bypass dampers will be provided. The control will be via CRT or panel mounted selector switches.

(4) *Indication.* Indication will be provided for compartment pressures and temperatures, baghouse inlet pressures and temperatures, and baghouse outlet pressures and temperatures. The indication will be via CRT or panel mounted indicators.

(5) *Annunciation.* Alarm conditions of the air quality control system should be audible and visually annunciated in the control room. Annunciation may be via CRT and printer or a panel mounted annunciator as described in *c(5)* above.

g. Continuous emissions monitoring systems controls. The continuous emissions monitoring system (CEMS) controls will be located in an air conditioned and heated environment. The controls will be microprocessor based and include all printers, displays and equipment necessary to save all data and generate reports required by the EPA. Malfunction of equipment will be annunciated in the control room.

9-6. Field Instrumentation.

a. General. Transmitters, control drives, control valves and piping instrumentation will be provided to sense the process variables and allow the control system to position the valves and dampers to control the process. All field devices shall be designed to operate in a dust laden atmosphere with temperature conditions varying from 20 to 160 degrees F.

b. Field transmitters.

(1) *General.* Electronic transmitters should produce a 4-20 mA dc signal that is linear with the measured variable. Electronic transmitters will be the two wire type except when unavailable for a particular application. Encapsulated electronics are unacceptable in any transmitter. Transmitters will be selected such that the output signal represents a calibrated scale range that is a standard scale range between 110 and 125 percent of the maximum value of the measured process variable. Transmitters will be designed for the service required and will be supplied with mounting brackets. Purge meters and differential regulators will be used on transmitters for boiler gas service or coal-air mixture service. A change in the load on a transmitter within the transmitter load limits will not disturb the transmitted signal. The load limits of the transmitter will be a minimum of 600 ohms. Transmitters can be supplied with local indicators, either integral or field mounted, if desired. Transmitters used for distributed control systems should be the "smart" type which have duplex digital communications ability transparent to the analog signal. Smart transmitters may be remotely calibrated via a hand held terminal. Data available at the hand held terminal should include programmed instrument number, instrument ID or serial number, instrument location, date of last calibration, calibrated range and diagnostics.

(2) *Flow transmitters.* Numerous types of flow transmitters are available. These include differential pressure with square root extractor, turbine flowmeters, nutating disk type transmitter, ultrasonic flow transmitters, and magnetic flowmeters. The most common method for measuring flow is to measure differential pressure across an orifice, flow nozzle, venturi, pitot tube, or piezometer ring. Square root extraction is necessary to linearize the output signal. Differential pressure measurement should be used for most steam plant flow applications. Nutating disk with pulse to 4-20 mA transmitters are normally used for fuel oil flow measurement. Flow transmitters will be accurate within 0.5 percent of span from 20 to 100 percent span with ambient temperature effect not to exceed 1.0 percent per 100 degrees F variation.

(3) *Level transmitters.* Measuring elements for level transmitters will be diaphragm, bellows, bourdon tube, strain gage transducer, caged float, or sealed pressure capsule. Level transmitters will be accurate within 0.5 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F variation. The output signal will be linear with the sensed level.

(4) *Pressure transmitters.* Measuring elements for pressure transmitters will be diaphragm, bellows, bourdon tube, or strain gage transducers. Pressure transmitters will be accurate within 0.5 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F variation. Measuring elements for pressure differential transmitters will be diaphragm, bellows, or sealed pressure capsule. Pressure differential transmitters will be accurate within 0.25 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F variation. Output signals for pressure and pressure differential transmitters will be linear with the sensed pressure or differential pressure.

(5) *Temperature sensors.* Several types of sensors can be used for temperature measurement. Thermocouples sense temperature by a thermoelectric circuit which is created when two dissimilar metals are joined at one end. A wide variety of thermocouples are available for temperature sensing. Type J (iron-constantan) and type K (chromel-alumel) are the most common types of thermocouples for boiler plant applications. Type J thermocouples can be used for temperatures from 32 to 1382 degrees F. Type K thermocouples can be used for temperatures from -328 to 2282 degrees F. The type of thermocouple to be used, Type J or Type K, will be selected based upon the temperatures to be sensed. All thermocouples in the boiler plant will be of the same type. Resistance Temperature Detectors (RTD) sense temperature based upon the relationship between the resistivity of a metal and its temperature. The most common RTD used in boiler plant applications is a platinum RTD with a resistance of 100 ohms at 0 degrees C. Sealed bulb and capillary sensors detect temperature by sensing the change in volume due to changes in temperature of a fluid in a sealed system.

(6) *Temperature transmitters.* Measuring elements for temperature transmitters should be thermocouple, RTD, or sealed bulb and capillary. Temperature transmitters will be accurate within 0.5 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F degree variation. Output signals for temperature transmitters will be linear with the sensed temperature.

(7) *Oxygen analyzers.* Oxygen analyzers will be direct probe type utilizing an in situ zirconium sensing element. The element will be inserted directly into the gas stream and will directly contact the process gases. The sensing element will be provided with a protective shield to prevent direct

impingement of fly ash on the sensing element. The analyzer should be equipped to allow daily automatic calibration checks without removing the analyzer from the process. The cell temperature in the analyzer will be maintained at the proper temperature by a temperature controller. The analyzer will be certified for "in stack" analysis technique in accordance with the Factory Mutual (FM) approval guide. The analyzer will be furnished with all accessories necessary for a complete installation.

(8) *Opacity monitors.* Opacity monitors use the principal of transmissometry to indicate level of particulate emissions. A beam of light is projected across the flue gas stream and a detector registers variations in the light transmittance caused by the particulate in the flue gas.

(9) *Flue gas monitors.* Flue gas monitors will be provided for all items required for EPA reports. Flue gas monitors are either in situ or extractive. In situ monitors are attached directly to the stack or breeching and access for maintenance should be provided. Extractive systems are wet, dry or diluted. Wet extractive system sample line should be heated to avoid corrosion. Dry systems utilize a cooler to remove water. Dilution systems utilize clean dry air to dilute the sample eliminating the need to heat the sample lines or dry the sample. Either in situ or extractive flue gas monitors should be used and not a mixture of the two for the various gases to be analyzed. All analyzers should be provided with self calibration features and have contact outputs for control room annunciation.

c. Control drives. Control drives will be used for positioning of control dampers, isolating dampers, and other devices requiring mechanical linkages. Control drives may be pneumatic or electric and are either open-shut type or modulating type depending on the application. Modulating drives may include position transmitters. Control drives will have adjustable position limit switches wired to terminal blocks, handwheels or levers for manual operation, hand locks or be self locking, position indicators, and adjustable limit stops at maximum and minimum positions. Drive arms and connecting linkages will be supplied with the damper drives. Control drives will have stroking times as required by the service and by NFPA recommendations.

(1) *Pneumatic control drives.* Pneumatic control drives should consist of a double acting air cylinder with rigid support stand and weatherproof enclosure. Pneumatic control drives for outdoor service will have thermostat controlled space heaters installed and wired to terminal blocks. Pneumatic control drives for modulating service will have positioners with characterizable cams. Open/shut control drives should have internally mounted four-way solenoid valves. Control drives will be designed to provide the rated torque with a maximum 50 psig air supply. The control drive will be sized to provide 150 percent of the torque required to drive controlled device.

(2) *Electric control drives.* Electric control drives will consist of an electric motor, gear box, rigid support stand, and wiring termination enclosure. Electric control drives will be weatherproof. The gear box will be dust tight, weather tight, and totally enclosed. Electric control drives will be self-locking on loss of control or drive power. Drives for outdoor installation will be designed to operate with ambient conditions of -20 degrees F and a 40 miles per hour wind. Drives will have adjustable torque limit switches and position limit switches. Electric drives will be supplied with motor starters, position controllers, speed controllers, characterizable positioners, transformers, and other accessories as required. The control drive will be sized to provide 150 percent of the torque required to drive the controlled device.

d. Control valves.

(1) *Valve bodies.* Control valve bodies will be constructed in accordance with the applicable ANSI codes. Control valves will be globe type unless otherwise required for the particular process. Butterfly valves may be used in low pressure water systems. Globe valves will have a single port designed to meet the design conditions. Restricted ports should be used when necessary for stable regulation at all loads. Special consideration will be given to valves which pass flashing condensate to assure adequate port and body flow area. The valve body size may be smaller than the line size if the plug guide is sufficiently rugged to withstand the increased inlet velocity, but valve body size will not be smaller than one half the line size. End preparations will be suitable for the applicable piping system. Valves will have teflon packing for temperatures not exceeding 450 degrees F. Bonnet joints will be flanged and bolted type and designed for easy disassembly and assurance of correct valve stem alignment. Valve trim will be cage guided and removable through the top after bonnet removal. Seat rings will be easily replaceable. Flow direction should be flow opening unless otherwise required.

(2) *Valve operators.* Control valve operators will be pneumatic diaphragm actuated type except where piston actuators are required. Valve operators will be adequate to handle unbalanced forces that occur from flow conditions or maximum differential. Allowances for stem force based on seating

surface will be made to assure tight seating. Diaphragms will be molded rubber and diaphragm housing will be pressed steel. Piston operators will use cast pistons and cylinders with 0-ring seals. Each valve operator will have an air supply pressure filter regulator. Valve operators for modulating service valves in fast response control loops, such as flow control or pressure control, will have electropneumatic valve positioners. Limit switches will be provided if needed for remote indication or control logic.

(3) *Control valve sizing.* Proper control valve sizing requires careful analysis of the process and piping system in which each valve is to be used. It is necessary to calculate the required valve flow coefficients based upon flow, valve inlet pressure, valve outlet pressure, and process fluid conditions. Calculations will be based on ISA S75.01. Valve flow coefficients will be calculated at the maximum, intermediate, and minimum process flow conditions. The control valves will be selected such that the maximum flow coefficient occurs at a valve travel between 70 and 80 percent. The minimum flow coefficient will occur at a valve travel between 10 and 20 percent. Control valves will be selected with a flow characteristic which provides uniform control loop stability over the range of process operating conditions. A quick opening flow characteristic provides large changes in flow at small valve travels and should primarily be used for on-off service applications. With a linear flow characteristic, the flow rate is directly proportional to valve travel. Valves with linear flow characteristics will be used for liquid level control where the ratio of the maximum valve pressure differential to the minimum valve pressure differential is less than five to one. Linear flow characteristic valves will also be used for pressure control of compressible fluids and for flow control when the flow rate varies but the valve pressure differential is constant. With an equal percentage flow characteristic, equal increments of valve travel produce equal percentage changes in the existing flow rate. Equal percentage flow characteristic valves will be used for liquid level control when the ratio of the maximum valve pressure differential to the minimum valve pressure differential is greater than or equal to five to one. Equal percentage flow characteristic valves will also be used for pressure control of liquids and for flow control when the valve pressure differential varies but the flow rate is constant. Special inner valve trim characteristics are required on applications where flashing or cavitation exist in liquid service and for noise control in steam or gas service.

(4) *Control valve stations.* Control valve stations are used to install control valves in piping systems and to provide a means of isolating and bypassing the control valve for maintenance purposes. Control valve stations will conform to the recommendations of ISA RP 75.06. Control valve stations consist of a control valve, isolating valves, bypass valve, and bypass line. Since control valves are normally smaller than the line size, reducers are required and can be integral to the control valve on valves with butt weld end connections. Isolation valves are required to isolate the control valve for repair, removal, or calibration and will be installed on the inlet and outlet sides of the control valve. Isolation valves will be gate valves or other non-throttling type valves. A bypass valve is necessary to provide a means of controlling the process when the control valve is not operable. The bypass valve will be identical to the control valve except it will be manually operated. Using an identical valve on the bypass provides better control during manual operation since the valve will have the proper flow coefficient and special valve trim. The bypass line which contains the bypass valve must be smaller than the main line size. The bypass line may be the same size as the bypass valve but in no case will the bypass line be smaller than one half the main line size.

e. Piping instrumentation.

(1) *Pressure switches.* Pressure switches are used to monitor pressures for remote indications, interlocking functions, and alarm conditions. Pressure switches may have snap acting switch contacts or mercury switch contacts. Shutoff valves of the same pressure and temperature rating as the process piping will be provided on each switch for isolation purposes. Snubbers will be provided on switches when the pressure connection is located within 15 pipe diameters of a pump or compressor discharge.

(2) *Pressure gauges.* Pressure gauges are used to provide local and remote indication of process pressures. Scale ranges will be selected such that the normal operating pressure is at approximately mid-scale. Shutoff valves of suitable rating will be provided on each gauge for isolation purposes. Snubbers will be provided on gauges when the pressure connection is located within 15 pipe diameters of a pump or compressor discharge. Siphons will be provided on pressure gauges for steam service. Pressure gauges will be provided on the discharge of all pumps and compressors, all boiler drums, all main process headers, and other locations as required to monitor equipment and process operation.

(3) *Thermometers.* Thermometers are used to provide local indication of process temperatures. Thermometers are normally the bimetallic type for most applications. Scale ranges will be selected such that the normal operating temperature is at approximately mid-scale. Thermometers will be provided with thermowells so the thermometer sensing element is not inserted directly into the process. Thermowells will be designed to withstand the pressure, temperature, and fluid velocities of the process in which they are inserted. Thermowells installed in piping will be long enough to extend to approximately the pipe centerline. Thermowells will have extensions to clear insulation and lagging.

(4) *Thermocouples.* Thermocouples are used to provide remote indication and control of process temperatures. Type J or Type K thermocouples are normally suitable for steam plant applications as discussed in paragraph 9-6b(5). Thermocouples will be provided with thermowells or protection tubes of suitable rating. Thermowell or protection tube length will be sufficient to provide the necessary insertion length plus the desired nipple length. Thermocouple assemblies will also include insulators and terminal head with cover.

(5) *Temperature switches.* Temperature switches are used to monitor temperatures for remote indications, interlocking functions, and alarm conditions. Temperature switches may have snap acting switch contacts or mercury switch contacts and may be bulb and capillary type or direct insertion type. Thermowells of suitable rating will be supplied so the sensing element is not inserted directly into the process.

(6) *Pressure controllers.* Pressure controllers will be pneumatic with bourdon tube or bellows sensing element. The sensing element will be suitable for the pressure and temperature of the process fluid to be controlled and will be an integral part of the controller assembly. The sensing element will have adequate sensitivity and be able to withstand the maximum pressure under all conditions. Pressure controllers will have adjustable proportional and reset control action, control point adjustment, calibrated pressure setting dial, air supply filter regulator, and gauges which indicate air supply and controller output pressures. Pressure controllers will be mounted on the operator of the valve to be regulated.

Table 9-4. Operator Interface Instrumentation Requirements.

Gas/Oil Fired Boilers		*Stoker Fired Boilers*		*Pulverized Coal Fired Boiler*	
Operator Stations:					
1. Boiler Master	R	1. Boiler Master	R	1. Boiler Master	R
2. Air Flow	X	2. Air Flow	R	2. Air Flow	R
3. Fuel flow	X	3. Fuel Flow	R	3. Pulverizer Master	X
4. Drum Level	R	4. Drum Level	R	4. Pulverizers	R
5. Oxygen Trim	X	5. Oxygen Trim	X	5. Primary Air	R
6. Furnace Pressure		6. Furnace Pressure	R	6. Drum Level	R
7. Steam Temperature		7. Steam Temperature	R	7. Oxygen Trim	R
(SH only)	R	(SH only)		8. Furnace Pressure	R
8. Deaerator		8. Deaerator		9. Steam Temperature	
Pressure	X	Pressure	X	(SH only)	R
9. Deaerator Level	X	9. Deaerator Level	R	10. Deaerator Pressure	X
10. Feedwater Heater	X	10. Feedwater Heater	X	11. Deaerator Level	R
		11. Steam Coil		12. Feedwater Heater	X
		Preheater	R	13. Steam Coil	
				Preheater	R
Recorder Requirements:					
1. Steam Pressure	R	1. Steam Pressure	R	1. Steam Pressure	R
2. Steam Flow	X	2. Steam Flow	R	2. Steam Flow	R
3. Fuel Flow	X.	3. Steam Temperature		3. Steam Temperature	
4. Drum Level	R	(SH only)	R	(SH only)	R
5. Percent Oxygen	R	4. Feedwater Flow	R	4. Feedwater Flow	R
6. Steam Temperature		5. Feedwater	X	5. Feedwater	X
(SH only)	R	Temperature		Temperature	
7. Deaerator	X	6. Deserator	K	6. Deaerator	X
Pressure		Pressure		Pressure	
8. Deaerator Level	K	7. Deaerator Level	X	7. Deaerator Level	K
9. Feedwater Temp	X	8. Drum Level	R	8. Drum Level	R
10. Exit Gas Temp	R	9. Air Flow	R	9. Total Air Flow	R
11. Feedwater Flow	R	10. Percent Oxygen	R	10. Percent Oxygen	R
12. Air Flow	X	11. Fuel Flow	K	11. Total Fuel Flow	K

Table 9-4. Operator lnterface lnstrumentation Requirements. (Continued)

Gas/Oil Fired Boilers		***Stoker Fired Boilers***		***Pulverized Coal Fired Boiler***	
		12. Combustion Air Temperatures	X	12 Combustion Air Temperatures	X
		13. Exit Gas Temperatures	R	13. Exit Gas	R
Indicators:					
1. Steam Pressure	R	1. Steam Pressure	R	1. Steam Pressure	R
2. Drum Level	R	2. Drum Level	R	2. Drum Level	R
3. Furnace Pressure	R	3. Furnace Pressure	R	3. Furnace Pressure	R
4. Combustion Air Pressure	R	4. Combustion Air Pressures	R	4. Combustion Air Pressures	R
5. Exit Air Pressures	R	5. ExitGas Pressure	R	5. ExitGas Pressures	R R
6. Feedwater Pressures	R	6. Feedwater Pressures	R	6. Feedwater Pressures	R
7. Feedwater Temperature	R	7. Feedwater Temperature	R	7. Feedwater Temperature	R
8. FD Fan Amps	R	8. ID Fan Amps	R	8. Pulverizer Outlet Temperature	R
9. Boiler Feed Pump Amps	R	9. FD Fan Amps	R	9. ID Fan Amps	R
10. Sootblower Pressure	X	10. Boiler Feed Pump Amps	R	10. FD Fan Amps	R
11. Gas Pressure	X	11. Sootblower Pressure	K	11. PA Fan Amps	R
12. Oil Pressure	X			12. Boiler Feed Pump Amps	R
				13. Sootblower Pressure	X
Integrators:					
1. Steam Flow	X	1. Steam Flow	X	1. Steam Flow	X
2. Fuel Flow	X	2. Fuel Flow	X	2. Fuel Flow	X
3. Feedwater Flow	X	3. Feedwater Flow	K	3. Feedwater Flow	X
Equipment start-stop controls:					
1. FDFans	R	1. ID Fans	R	1. IDFans	R
2. Boiler Feed Pumps	R	2. FD Fans	R	2. FD Fans	R
		3. Boiler Feed Pumps	R	3. PA Fans	R
				4. Boiler Feed Pumps	R
				5. Pulverizers	R
				6. Coal Feeders	R

ACFB Fired Boilers			
Indicators:			
1. Furnace pressure	R	23. Fuel flow	R
2. J-valve outlet static pressure	R	24. Sorbent (limestone) flow	R
3. J-valve inlet static pressure	R	25. Steam temperature	R
4. J-valve discharge pressure	R	26. Furnace exit gas temperature	R
5. Over furnace bed static pressure	R	27. Solids cooler stripper section temperature	R
6. Furnace plenum pressure	R	28. Solids cooler cooler cooler section temperature	R
7. Steam pressure	R	29. J-valve fluid temperature	R
8. Spray water pressure	K	30. Furnace bed individual TC temperature	X
9. J-valve dipleg (diff press)	R	31. Furnace bed average temperature	R
10. J-valve density (duff press)	R	32. Furnace plenum temperature	R
11. Valve solids flow (diff press)	R	33. Feedwater temperature	K
12. Bed differential pressure	R	34. Oxygen	R
13. Total furnace differential pressure	R	35. SO_2	R
14. Primary air flow	R	36. Drum level	R
15. Overfire air flow	R	37. Deasrator pressure	X

Table 9-4. Operator lnterface lnstrumentation Requirements. (Continued)

ACFB Fired Boilers

16. J-valve plenum air flow upleg	R
17. J-valve plenum air flow downleg	R
18. Total air flow	R
19. Steam flow	R
20. Spray water flow	X
21. Feedwater flow	R
22. Gas flow	R
38. Deaerator level	X
39. Cyclone level (uses diff press transmitters)	R
40. Chute air flow	R

Operator Stations:

1. Boiler master	R
2. Primary air flow	R
3. Overfire air flow	R
4. Oxygen trim	R
5. Fuel master	X
6. Fuel flow	R
7. Airflow	R
8. Furnace pressure	R
9. FD fan discharge pressure	R
10. Stripper cooler air flow	R
11. Solids cooler spray water	R
12. J-valve blower discharge pressure	R
13. J-valve aeration control	R
14. J-valve plenum air control	R
15. Sorbent (limestone) feed	R
16. Furnace bed inventory	R
control	R
17. Drum level	R
18. Steam temperature (SH only)	R
19. Warm-up burner control	R
20. Deaerator pressure	X
21. Deaerator level	R
22. Feedwater heater	X
23. Steam coil preheater	R

Recorder Requirements:

1. Furnace pressure pressure	R
3. J-valve inlet static pressure	R
4. J-valve discharge pressure	R'
5. Over furnace bed static pressure	R
6. Furnace plenum pressure	R
7. Steam pressure	R
8. Spray water pressure	X
9. J-valve diplet (duff press)	R
10. J-valve density (duff press)	R
11. Valve solids flow (diff press)	R
12. Bed differential pressure	R
13. Total furnace differential pressure	R
14. Primary air flow	R
15. Overfire air flow	R
16. J-valve plenum air flow upleg	R
17. J-valve plenum air flow downieg	R
18. Total air flow	R
19. Steam flow	R
20. Spray water flow	X
21. Feedwater flow	R
22. Gas flow	R
23. Fuel flow	R
24. Sorbent (limestone) flow	R
25. Steam temperature	R
26. Furnace exit gas temperature	R
27. Solids cooler stripper section temperature	R
28. Solids cooler cooler section temperature	R
29. J-valve fluid temperature	R
30. Furnace bed individual TC temperature	X
31. Furnace bed average temperature	R
32. Furnace plenum temperature	R
33. Finish SH inlet temperature	X
34. Feedwater temperature	X
35. Oxygen	R
36. SO[sub]2	R
37. Drum level	R
38. Deaerator pressure	X
39. Deaerator level	X
40. Cyclone level (uses duff press transmitters)	R
41. FD fan discharge pressure	R
42. Solids cooler stripper airflow	R
43. Solids cooler solids air	R
flow	R
44. Drum pressure	R
45. Warmup burner discharge temperature	R
46. Air heater inlet air temperature	R
47. Air heater gas temperature	R
48. Air heater cold end temperature	R
49. ID fan amps	R
50. FD fan amps	R
51. Boiler feed pump amps	R
52. Sootblower pressure	X

Table 9-4. Operator lnterface Instrumentation Requirement. (Continued)

ACFB Fired Boilers

Integrator			*Equipment Start-Stop Controls*	
1. Steam flow	R	1.	ID fans	R
2. Fuel flow	R	2.	FD fans	R
3. Feedwater flow	R	3.	PA fans	R
4. Sorbent flow	R	4.	Boiler feed pumps	R
		5.	Coal feeders	R
		6.	Sorbent (limestone) feeders	R
		7.	-valve blowers	R

R - Required
X - Optional